OLSON, BZDOK & HOWARD

November 7, 2018

Ms. Kavita Kale ***Via E-Filing***
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20162

Dear Ms. Kale:

The following is attached for paperless electronic filing:

Direct Testimony of Karl R. Rábago on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club

Exhibits MEC-13 through MEC-31, MEC-21 is Reserved

Proof of Service

Sincerely,

Digitally signed by Christopher M. Bzdok
DN: cn=Christopher M. Bzdok, o=Olson Bzdok & Howard, P.C., ou, email=chris@envlaw.com, c=US
Date: 2018.11.07 16:46:16 -05'00'

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xc: Parties to Case No. U-20162
James Clift, MEC
David Bender, Earthjustice

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	Case No. U-20162 ALJ Sally L. Wallace

DIRECT TESTIMONY OF KARL R. RÁBAGO

ON BEHALF OF

NATURAL RESOURCES DEFENSE COUNCIL, MICHIGAN ENVIRONMENTAL COUNCIL, AND SIERRA CLUB

November 7, 2018

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I. INTRODUCTION

Q. Please state your name, business name and address, and role with the Natural Resources Defense Council, Michigan Environmental Council and Sierra Club.

A. My name is Karl R. Rábago. I am the principal of Rábago Energy LLC, a New York limited liability company, located at 62 Prospect Street, White Plains, New York. I appear here in my capacity as an expert witness on behalf of the Natural Resources Defense Council, Michigan Environmental Council and Sierra Club.

Q. **Please summarize your experience and expertise in the field of electric utility regulation.**

A. I have worked for more than 28 years in the electricity industry and related fields. I am actively involved in a wide range of electric utility issues across the United States, as an expert witness, and in my capacity as executive Director of the Pace Energy and Climate Center, as a party in New York rate cases and in Reforming the Energy Vision proceedings. My previous employment experience includes Commissioner with the Public Utility Commission of Texas, Deputy Assistant Secretary with the U.S. Department of Energy, Vice President with Austin Energy, and Director with AES Corporation, among others. A detailed resume is attached as Exhibit MEC-13.

Q. Do you have a specific experience related to distributed energy resources, including distributed solar generation?

A. Yes. I have extensive experience working in the field of distributed energy resources, a category of energy resources that includes distributed generation, energy efficiency, energy management, energy storage, and other technologies and related services. That experience includes regulation of electric utilities in Texas, including review and approval of rates,

tariffs, plans, and programs proposed by electric utilities. I co-authored the seminal treatise on distributed energy resource value, entitled "Small Is Profitable,"[1] when I was a managing director at the Rocky Mountain Institute. I have also published several articles and essays relating to the topic, as detailed in my resume. As a vice president for Distributed Energy Services for Austin Energy, I had responsibility for all of the utility's customer-facing programs relating to distributed solar generation, energy efficiency, demand management, low-income weatherization, energy storage, electric transportation, building energy ratings and codes, and the utility's electric vehicle initiatives. While with Austin Energy, one of the largest municipal electric utilities in the nation, I developed and implemented the nation's first distributed solar tariff, based on objective and comprehensive valuation of solar generation, often referred to as Austin Energy's "Value of Solar Tariff." At the U.S. Department of Energy, I was the federal executive responsible for the nation's research, development, and deployment programs relating to renewable energy, energy efficiency, energy storage, and other advanced energy technologies in the Department's Office of Utility Technologies. In my current position with the Pace Energy and Climate Center, based at the Pace University Elisabeth Haub School of Law in White Plains, New York, I lead a team that is actively engaged as a public interest intervenor in the ground-breaking "Reforming the Energy Vision" process administered by the New York Public Service Commission. The Pace Energy and Climate Center is committed to growing self-sustaining markets for distributed energy resources in order to save money for consumers and utilities, advance free market competition, and address environmental challenges. I am a frequent speaker, commentator, and expert witness across the country

[1] Amory B. Lovins, et al., Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size, Rocky Mountain Institute (2003). Witness Rábago was a co-author of the book.

on issues relating to electric utility regulation, distributed energy resource markets and technologies, and electricity-sector market reform.

Q. Have you ever testified before the Michigan Public Service Commission ("MPSC" or "Commission") and other regulatory agencies?

A. Yes. I provided testimony in MPSC Cases U-17302, U-17301, U-17767, U-18090, U-18091, U-18089, U-18092, U-18093, U-18094, and U-20134. In the past six years, I submitted testimony, comments, or presentations in proceedings in Arkansas, Arizona, California, Colorado, Connecticut, Florida, Georgia, Guam, Hawaii, Indiana, Iowa, Kansas, Kentucky, Louisiana, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, Vermont, Virginia, and Wisconsin, and before the U.S. Congress, the Federal Energy Regulatory Commission, and the Federal Trade Commission. A listing of my recent previous testimony, which includes testimony in a wide range of public service commission proceedings relating to solar tariffs, distributed energy resources, grid modernization, electric utility transformation, and utility planning and rate making, is attached as to my resume.

Q. What materials did you review in preparing this testimony?

A. I reviewed applicable provisions of Michigan Compiled Laws, the application and testimony of DTE Energy ("Company") in this proceeding, Company and Commission reports and websites, and Company and other party responses to requests for discovery from other parties in this case.

Q. Do you have any business relationships with the Company?

A. I do not have any direct business relationships with the Company, its parent company, or any affiliates. I sit as Chair of the Board of Directors for the Center for Resource Solutions ("CRS"). CRS is a not-for-profit California corporation that offers certification services to green pricing and green power products throughout the U.S., under the certification mark called the "Green-e." The Company's GreenCurrents℠ green pricing service is currently certified under the Green-e Energy program and pays a fee to the Center for Resource Solutions for use of the certification mark. I have no direct involvement with the certification of programs under the Green-e Energy program and I will not be involved with matters directly relating to the Company's certification. Consistent with the conflict of interest policy adopted by the CRS Board, I have notified my fellow board members of my participation in this proceeding as an expert witness.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring 19 exhibits:

MEC-13	Resume of Karl Rabago
MEC-14	MECNRDCSCDE-8.18
MEC-15	MECNRDCSCDE-8.19
MEC-16	MECNRDCSCDE-1.18d
MEC-17	MECNRDCSCDE-1.23 responses with Attachment c
MEC-18	MECNRDCSCDE-2.11
MEC-19	U-18255 MECNRDCSCDE-1.19
MEC-20	MECNRDCSCDE-8.20
MEC-21	Reserved
MEC-22	ELPCDE-2.84 with Attachment

MEC-23	ELPCDE-1.24a-g
MEC-24	MECNRDCSCDE-1.17d
MEC-25	MECNRDCSCDE-3.4a
MEC-26	MECNRDCSCDE-3.9
MEC-27	MECNRDCSCDE-1.10a
MEC-28	MECNRDCSCDE-1.2 Revised
MEC-29	MECNRDCSCDE-1.11
MEC-30	MECNRDCSCDE-3.6a
MEC-31	MECNRDCSCDE-3.16b

Q. What is the purpose of this testimony?

A. In this testimony, I address and recommend that the Commission deny the Company's proposals (1) for increased fixed customer charges for residential and small commercial customers based on the collection of demand-related costs through the customer charge, (2) for distributed generation Rider 18, comprised of a System Access Contribution ("SAC") charge and an outflow credit as a replacement for net metering, among other things, and (3) for rate recovery of dues paid to Edison Electric Institute.

Q. How is this testimony organized?

A. My testimony is organized as follows:

- Introduction (see above)
- The Company's Proposal to Increase Fixed Customer Charges for Residential Rate D1 and Small Commercial Rate D3 Customers and Recover Demand-Related Costs through the Fixed Customer Charge

- The Company's Proposal for a New Distributed Generation Rider 18 and an Inflow/Outflow Distributed Generation Tariff
- The Company's Proposal to Charge Customers for Edison Electric Institute Dues
- Recommendations to the Commission

II. THE COMPANY'S PROPOSAL TO INCREASE FIXED CUSTOMER CHARGES FOR RESIDENTIAL RATE D1 AND SMALL COMMERCIAL RATE D3 CUSTOMERS AND TO RECOVER DEMAND-RELATED COSTS THROUGH THE FIXED CUSTOMER CHARGE

Q. Please describe the Company's proposal to increase the residential fixed customer charge.

A. The Company proposes, primarily through the testimony of Company witnesses Lacey and Dennis, to increase in the fixed residential (rate D1) customer charge from $7.50 to $9.00 per customer per month, and from $11.25 to $15.00 per customer per month for general service customers on rate D3.

Q. What is the basis for the Company's proposal to increase fixed customer charges for residential and commercial secondary customers?

A. The Company takes the position that all of what it classifies as "non-variable demand costs" should be recovered through a demand charge. In lieu of a demand charge for small customers—because the Company is not prepared to implement a residential demand charge—the Company proposes that it is most appropriate to recover demand-related costs through a fixed customer charge. For residential customers, the Company classifies about $1.092 billion in costs as eligible for recovery through the fixed customer charge.[2] Based

[2] Company Exh. A-16, Sched. F1.4.

on about 2 million customers, the Company takes the position that the monthly customer charge for residential customers should be $45.53 per customer per month.[3] For commercial secondary customers, the Company classifies about $444 million in costs as eligible for recovery through the fixed customer charge.[4] Based on about 207,000 of these customers, the Company takes the position that the monthly customer charge for commercial secondary customers should be $178.88 per customer per month.[5] The Company's proposal to increase the fixed customer charges for residential and commercial secondary customers in this case is a proposed first step in the Company's overall attempt to incrementally raise the fixed customer charge or other non-volumetric charges until it recovers $45.53 and $178.88 or more per customer per month, respectively, in revenues that do not vary with the level of customer energy use.[6]

Q. Has the Company tried increasing fixed customer charges in previously filed rate applications?

A. As in prior cases, the Company seeks a rate design for residential and small commercial customers (1) that improperly shifts recovery demand-related costs from a volumetric charge to the fixed customer charge; (2) that is economically regressive and shifts recovery of these costs from high users and cost-causers to low users; (3) that weakens price signals for economically efficient use of energy and investment in energy resources; and (4) that weakens incentives to the Company to improve load forecasting and to seek out and make the most economic choices in distributed resource investments.

Q. How has the Commission responded to these efforts in the past?

[3] *Id.*
[4] *Id.*
[5] *Id.*
[6] *Id.*

A. The Company has been clear and unequivocal that fixed customer charges should be reserved for the recovery of the marginal costs of connecting customers to the electric system.[7]

Q. Why does the Company assert it is appropriate to recover demand-related revenues through a fixed customer charge?

A. The Company asserts that "[c]ost causation should match cost recovery as much as possible; therefore, all distribution costs, demand and customer related, should be collected through the customer charge."[8]

Q. Is the Company justification a valid statement of sound regulatory policy?

A. No. It is true that rates should be assigned to cost causers in order to advance fairness and economic efficiency. But the Company implies that the *form* of costs should be replicated in the *form* of the rate design. There is no authority in economic or regulatory literature that supports a principal that fixed costs should be recovered in fixed costs simply because they are designated as fixed, or in the words of the Company, "non-variable." There is no evidence that this approach maximizes or even increases economic efficiency, for monopoly utilities or for competitive businesses. Finally, there is no principle of rate making that holds that the label assigned to a cost should dictate rate design structure.

Q. Is the Company proposal supported by facts in record?

A. No. The Company offers no evidence, and provided none through discovery, to support any contention that demand charges or fixed charges are better correlated with cost of

[7] MPSC Order, Case No. U-18255 (Apr. 18, 2018) at p. 65. *See also* MPSC Order, Case No. U-18014 (Jan. 31, 2017 at p. 107; MPSC Order, Case No. U-17767 (Dec. 11, 2015) at p. 119.

[8] Lacey direct testimony at p. 20:1-3. *See also* Company responses to Exhibit MEC-14 discovery responses MECNRDCSCDE-8.18 and Exhibit MEC-15 discovery response MECNRDCSCDE-8.19 which confirm that the Company's position is not supported by any arguments or evidence relating to economic efficiency, but only to the unsupported assertion that fixed charge recovery of demand charges "best matches cost causation to cost recovery."

service than customers' kWh consumption.[9] In other words, the Company's proposal to collect more costs through a higher fixed charge is unnecessary to secure just and reasonable cost recovery.

Q. What costs does the Company include in the classification of non-variable demand costs?

A. The Company classifies all demand infrastructure capital investment costs as non-variable. The Company also classifies all demand-associated operations and maintenance ("O&M") costs to the non-variable category.

Q. Do you agree with the Company's classification?

A. No. First, as noted above, the variable/non-variable designation is irrelevant for connecting those costs to appropriate rate components. Second, demand and O&M costs are not non-variable.

Q. What costs should the Company recover through the fixed customer charge?

A. The fixed customer charge should be reserved for the recovery of costs that vary exclusively with the number of customers and the cost to connect those customers to the grid. This is the Commission's standard, as previously explained. It is also consistent with sound rate making principles, which state that the customer function and, indirectly, the customer charge, should reflect the costs incurred by the utility to connect the average customer to the electric system for service. In 1961, James C. Bonbright defined the fixed customer charge as follows:

> [The customer costs] are those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption. Included as a minimum are costs of metering and billing

[9] Exhibit MEC-16 discovery responses to MECNRDCSCDE-1-18d. and Exhibit MEC-17 discovery response MECNRDCSCDE-1.23c.

> along with whatever other expenses the company must incur in taking on another consumer.[10]

Simply stated, Bonbright's definition, like the Commission's prior orders, ensures that the customer charge is limited to the marginal cost of connecting the customer to the grid, and should include only costs that vary directly with the number of customers.[11]

Q. What is the monthly bill impact of the proposed increase in fixed residential customer charges?

A. The Company seeks a 9.1% increase in residential revenues.[12] The proposed fixed charge increase is 20%.[13] This disproportionate increase to the fixed charge raises overall rates more for customers who use the least amount of electricity and provides a price signal to increase, rather than decrease, usage. The Company's bill impact estimates reveal that the greatest impact of the proposed fixed charge increases falls on the lowest users of electricity.[14] For example, for rate D1 customers who use 140 kWh per month, the bill for all charges would increase by 11.12%, while the percentage increase for customers that use ten times as much electricity, or 1,400 kWh per month, the bill would increase by 8.77%. In effect, the higher fixed customer charges for both residential and commercial secondary customers operate and communicate price signals like a declining block rate, a rate making approach that is inconsistent with efficient electricity operations and markets.

Q. Why is the fact that the proposed rate changes impose a greater burden on low energy residential users important, in addition to the price signal related to energy use?

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[10] Bonbright at 347.
[11] *See also,* Jim Lazar & Wilson Gonzalez, "*Smart Rate Design for a Smart Future* at 36 (2015), http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf
[12] Exh. A-16, F2, at p. 2.
[13] Calculated as ($9.00 - $7.50) / $7.50 = 20%.
[14] Exh. A-16, F4, at p. 2.

A. Low energy residential users are often low-income customers, fixed-income customers, and the elderly, whether or not they are enrolled in a discount rate. Customers who make significant investments in energy efficiency and self-generation fall into this category as well. For these residential customers, proposed rate changes like those proposed by the Company are economically regressive.

Q. What data are available about residential energy usage levels and income in Michigan?

A. The Company did not address the relationship between energy usage levels and income in its rate application. However, in discovery the Company cited low-income customer population numbers in the hundreds of thousands.[15] While the Company has a Residential Income Assistance program that provides a credit equal to the fixed charge, and a Residential Service Special Low Income Pilot program that provides a larger credit, the total number of credits available under these programs is much lower than DTE's total number of low income customers—leaving tens of thousands of lower income customers, or more, impacted by the higher fixed charge. Data obtained from the U.S. Energy Information Administration's Residential Energy Consumption Survey for 2009, the most recent data available, and published by the National Consumer Law Center ("NCLC"), which show that energy usage is closely correlated with household income in Michigan.[16]

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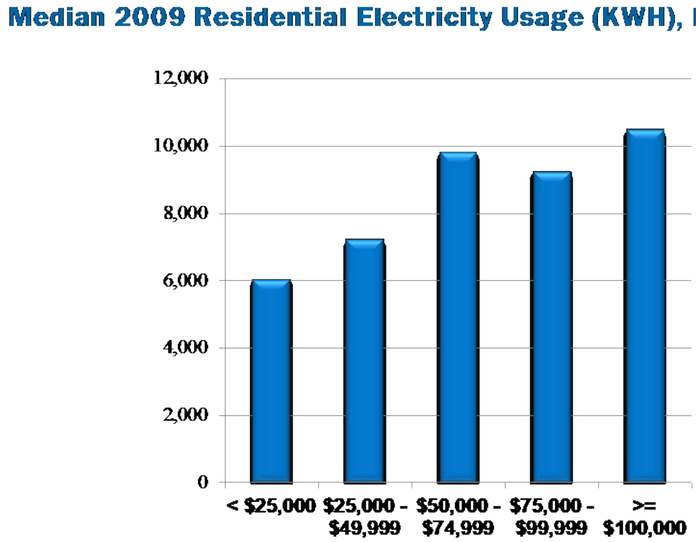
[15] Exhibit MEC-18, discovery response MECNRDCSCDE-2.11, Exhibit MEC-19 discovery response U-18255 MECNRDCSCDE-1.19 and attachment.
[16] "Utility Rate Design: How Mandatory Monthly Customer Fees Cause Disproportionate Harm," available at: http://www.nclc.org/images/pdf/energy_utility_telecom/rate_design/MI-FINAL2.pdf.

Figure 1: U.S. EIA Residential Energy Consumption Survey Data - Michigan 2009



In addition, according to the U.S. EIA data, median electricity usage is also lower for households with residents older than 65 years, and for the homes of racial minorities.

Figure 2: U.S. EIA Residential Energy Consumption Survey Data - Michigan 2009

2009 Residential Energy Consumption by Income, Race/Ethnicity, & Age

HOUSEHOLD INCOME	MEDIAN ELECTRICITY USAGE (KWH)
< $25,000	6,035
$25,000 - $49,999	7,221
$50,000 - $74,999	9,825
$75,000 - $99,999	9,243
>=$100,000	10,490

HOUSEHOLD RACE	MEDIAN ELECTRICITY USAGE (KWH)
Asian	6,477
African American	5,637
Caucasian	8,524
Latino	8,986

HOUSEHOLD AGE	MEDIAN ELECTRICITY USAGE (KWH)
65 years or older	6,842
Less than 65 years	8,034

Source: U.S. Energy Information Administration's Residential Energy Consumption Survey, 2009 (most recent data available)

Q. Does the Company need to increase fixed customer charges to avoid a financial integrity risk associated with volumetric rates?

A. No. In fact, the Company does not assert that increased fixed customer charges are necessary to address or avoid any financial integrity risk associated with revenue recovery.

First, the actual ratemaking principle is that rates should reflect costs, and not that labels applied in cost allocation should align with labels applied to monthly bill components. There is no statistical likelihood of any real risk to the Company's financial integrity due to overall residential and small commercial customer usage level variability in the interval between rate cases. The adverse impacts of high fixed charges on low use, low-income, and fixed income elderly customers, as well as upon the economics of efficient use of energy, discussed later in my testimony, outweighs any hypothetical risk to the Company's earnings. It should also be noted that if inter-rate case revenue variances were an actual concern, they could more reasonably be addressed through better forecasting and the use of future test year methods.

Q. Why is it appropriate to continue recovering so-called "fixed" costs through volumetric rates?

A. It is appropriate because of the price signal function of properly designed rates. Properly designed rates *reflect* properly allocated costs *and* send signals for efficient consumption in the future.

Q. Is recovery of fixed costs through volumetric charges consistent with principles of ratemaking and the economic efficiency of rates?

A. Yes. Sound ratemaking is based on ensuring that costs are properly allocated to customer classes based on cost causation. I know of no ratemaking or economic principle that finds that cost *structure* must be replicated in rate *design*, especially when significant negative policy impacts are attendant to that approach. Traditional rate making limits residential and small commercial customer charges to certain basic customer connection costs—the consumption measurement function of the meter, billing services associated with account

set up and disconnection, and other similar general and administrative costs that vary with customer count and with the cost to connect a customer to electric service. As the Commission has ordered on several prior occasions, this limited range of fixed costs should form the basis and ceiling for fixed customer charges.

Q. When costs associated with distribution systems are classified as fixed, should they be collected through the fixed customer charge?

A. Not necessarily, and not if the result is that low usage customers are disproportionately impacted, or adverse impacts on energy efficiency, conservation, and renewables result, as discussed later in my testimony. First, such a policy would depend on proper classification of fixed versus variable costs. Very few costs are actually fixed over the mid to longer term. Second, I am not aware of any evidence or analysis, and see none in this record, that increasing fixed customer charges improves system-wide economic efficiency or the efficiency of *customer* decisions.[17] Absent evidence of system-wide or customer efficiency benefits, fixed customer charges should not be increased, and demand-related costs should instead be allocated to volumetric charges. Again, there is no agreement on proper classification of costs as fixed or variable (including the time period for making that determination) and, even if there was, the differences in costs that lead to labeling them as fixed or variable do not, standing alone, tell us anything about the rate design that should be used to recover them.

Q. What is the key difference between fixed and variable costs?

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[17] The Company confirms that it has no such authority for such a proposition and is able to cite only a single advocacy piece supporting the use of customer charges to collect demand-related costs. *See* Company response to MECNRDCSCDE-8.20 Exhibit MEC-20.

A. The key discriminator for labeling a cost as fixed or variable is the element of time. It is important to remember that over the long term, all costs are variable; just as over the very short term, one could argue all costs are fixed. For example, distribution transformers are typically treated as a fixed cost because of their relatively long life. Loading on a transformer, especially during periods of high demand, will impact its useful life. As a result, demand reductions can extend the useful life of transformers. In order to send a price signal that will encourage the reductions in demand that could extend useful life and reduce revenue requirements in the future, a volumetric rate should be used. Demand charges for these costs may be appropriate for much larger customers whose individual demands have greater impact on the cumulative loads on the equipment and where customers have greater experience with and control over their usage levels and patterns.

Q. How do residential and small general service customers exercise control over their variable and fixed costs?

A. With volumetric rates to recover fixed and variable demand and energy costs, residential and small commercial customers have meaningful, practical, and realistic opportunities to exercise control over their energy bills and costs. As discussed below, reductions in use—through efficiency, conservation, or self-generation—all contribute to reductions in variable energy costs. Moreover, these behaviors also reduce high peak demand, and by doing so customers directly contribute to reduced fixed costs going forward. Efficiency, demand response, solar, storage, and other options allow customers to contribute to fixed cost reduction. All of these options are frustrated by shifting cost recovery for demand-related costs from volumetric to fixed monthly charges, as proposed by the Company. The overwhelming experience in the United States is that a utility can recover the exact same

amount of authorized revenue requirement through a volumetric charge and avoid such unwelcome consequences.

Q. Do fixed charges for demand-related costs send a meaningful price signal to customers?

A. No. There is no meaningful price signal in charging a rate that small customers cannot effectively respond to through modification in usage behavior. Recovering demand-related costs in fixed per-customer charges means customers are burdened with those charges regardless of the level of their use, and regardless of the time that they use electricity. The demand charges that the Company aspires to also collect from residential and small commercial customers in the future—charges based on sunk fixed costs—are also deeply flawed because most such customers lack meaningful tools for responding to them. This is one reason why there is no widely accepted regulatory principle that merely labeling a cost as "fixed" compels its recovery through a fixed customer charge or an effectively fixed demand charge. Indeed, if fixed charges for demand-related costs send any price signals at all, it is the perverse price signal that changes in usage, regardless of time of use, have no effect on bills—encouraging electricity waste.

To the extent that there are three theoretical options—demand charges, volumetric charges, or fixed charges—fixed charges are the worst for purposes of sending price signals. Demand charges are second worst, and for customer who have no affordable meaningful way to reduce demand, demand charges operate as fixed charges. Residential and small commercial customers have only limited options for changing their demand independently of their energy use, and this is especially true of renters. A customer's demand, especially for low-income and low use customers, is a function of the energy

performance of their home or business facility, which is often rented; their major appliances or equipment, which are often expensive to replace or upgrade; and the weather. These customers do have increasing options for reducing energy use, so allocating and recovering demand-related costs on the basis of volumetric energy consumption is the best rate design option for sending price signals for both energy and demand cost causation on a going-forward basis. A fixed charge for demand-related costs eliminates any potential price signal. Imposing higher demand-based fixed charges on these customers takes bread from the tables of these customers by increasing their energy bills while removing any tools to mitigate that burden and is the rate design equivalent of telling these customers to just "eat cake."

Q. How should the Company recover prudently-incurred demand-related fixed costs?

A. There is no reason to change the Commission's established approach on this issue. The prudently incurred demand-related costs (above those strictly associated with the cost of connecting the customer to the grid) that the Company proposes to allocate to fixed customer charges should be allocated to the volumetric rate. The Company has not demonstrated the reasonableness of its proposed rate design, especially in light of the potential adverse impacts discussed below and considering the relative impacts of alternative rate designs.

Q. Do the Company's proposals to increase the fixed customer charges, and potentially impose residential and small commercial demand charges in the future, help to stabilize the Company's revenues?

A. Maybe but not necessarily. Moreover, while it is understandable that the Company would try to fix a larger portion of its revenues collected from customers, it is not reasonable that

they should be allowed to do so. Fixed charges for demand-related investments send a price signal *to utilities* that recovery of their demand-related spending is not subject to variability in the level of customer demand and, therefore, there is no value to correctly predicting loads. If a utility company incorrectly forecasts greater demand than it ends up experiencing, it will have an overbuilt system and should experience a situation where sunk fixed costs are potentially unrecovered under current rates. Imposing on utilities the potential financial responsibility for unjustified overbuilding provides an efficient price signal to the utility to correctly predict loads by improving forecasting. It should also inspire investment in a smarter grid that leverages the potential benefits of all manner of flexible distributed energy resources as cost-effective alternatives to large, expensive, and inflexible resources. Shielding the utility from the consequences of unjustified overbuilding or of uneconomic resource decisions through fixed charge recovery of costs actually creates a perverse incentive in favor of economic waste. As explained later in the section discussing impacts on energy efficiency and distributed generation, the Company's proposal to increase fixed charges for residential and general service customers not only constitutes the bad choice, it frustrates the good ones.

Q. Can you provide an example of the price signal to the utility when demand costs are recovered through volumetric rates instead of fixed charges?

A. One example is that if the utility forecasts that demand on a particular feeder will be heavy, it may install a larger, more expensive transformer. The money spent on that transformer will be sunk. If load and sales do not grow as expected, the utility risks under-recovering the cost of the transformer. That provides a signal to the utility to make its forecasts as accurate as possible by putting risk of inaccurate forecasts on the utility, and to consider

alternatives, such as demand reductions, to the traditional transformer solution. In contrast, if the utility is guaranteed recovery of the over-sized transformer through fixed charges, it shifts risk of inaccurate forecasts to customers and discourages the search for more flexible alternative investments or spending.

Importantly, volumetric rates also simultaneously provide a price signal to customers to reduce their loading, which reduces the size of the *next* transformer and associated cost *in the future.* Energy efficiency, demand response, and other factors can reduce the fixed cost requirements in the future, and perhaps even allow for the installation of smaller replacement equipment. These measures can also extend the useful life of the installed fixed cost assets. Moving demand cost to the fixed charge, instead of the consumption based charge, provides no price signal to reduce consumption—simultaneously providing inefficient price signals to both utility and customers. The expected result is higher costs in the long term.

It is widely accepted—and a strong justification for grid modernization investments—that customers can reduce the requirement for expensive infrastructure investments by reducing their usage, especially during particular times of the day. These reductions arise because of reductions in system loading, which in turn reduces the need for costly system upgrades, reduces wear and tear (e.g., temperature-related degradation), and results in capital cost deferrals related to replacement. Higher volumetric charges for on-peak usage can further support demand response programs and energy storage deployment with similar results.

Q. Did the Company evaluate how customer demand would or might change in response to changes in rates?

A. No. The Company does not address the issue of price elasticity of demand. The Company did not produce customer usage information by household for residential customers or business income for commercial secondary customers. In order to support its application, the Company must produce competent evidence that its rates are at least likely to produce changes in consumption behavior that would track with economically efficient outcomes. In the absence of any evidence of elasticity coefficients for residential and small commercial customers under both existing and proposed rates, the Company cannot support a showing that its proposed rates are likely to be effective in this regard. The Company's application lacks a foundation on which to assert that its proposed rate design is just and reasonable.

Q. How do increased fixed customer charges specifically impact customer investment in energy efficiency and conservation?

A. Increases in fixed customer charges create powerful price signals *against* investment in energy efficiency, conservation, and renewables.

Q. Did the Company consider the impact of its proposed increase in the fixed customer charge on energy efficiency, conservation, and renewables?

A. The Company provided no evidence that it considered the impacts of its fixed charge proposals, or its future demand charge proposals, on energy efficiency, conservation, or renewables.

Q. Why should the Commission be concerned about approving a rate design that is detrimental to energy efficiency, conservation, and renewables?

A. Energy efficiency, conservation, and renewables offer many benefits to the people and State of Michigan. These benefits include resource diversification, grid resiliency, future

cost reductions associated with increased volume of deployment (economies of scale), job creation, system-wide cost reductions, and leveraging of non-utility investment dollars, among others.

Q. What result would you expect from allowing a monopoly electric utility to use fixed charges to recover fixed cost investments?

A. In a competitive market, a service provider would meet customer efforts to reduce and increase control over service bills with service innovations, operational efficiency, and price reductions. The logical result of using rate design to insulate a monopoly from market forces that would otherwise drive such benefits is that the monopoly will resist innovation and increase prices. In conclusion, the proposed increase in the fixed monthly charges for residential and small commercial customers are inimical to Michigan policy and utility sector transformation objectives.

Q. What action should the Commission take on the Company's fixed customer charge proposals for residential and small commercial customers?

A. I recommend that the Commission deny the Company proposals to increase the monthly customer charges. Consistent with its prior Orders, the Commission should direct the Company to remove demand-related investment costs beyond the cost to connect small customers and recalculate the monthly customer charge without those costs.

Q. In summary, does the Company's proposal to disproportionately increase fixed customer charges constitute sound economics, regulation, and policy?

A. No. Peter Kind, known as the author of the Edison Electric Institute's "Disruptive Challenges" paper, recognized in a paper published in November of 2015 that "many utilities have been seeking to increase fixed charges, while customers and policymakers

are vehemently opposed to such action. An evolved approach would focus on common ground with win4 (i.e. beneficial to customers, policy, competitive providers, and utilities) perspective." [18] As Kind further explained:

> Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit. Fixed charges:
>
> - do not promote efficiency of energy resource demand and capital investment;
> - reduce customer control over energy costs;
> - have a negative impact on low- or fixed-income customers; and
> - impact all customers when select customers adopt [distributed energy resources] and potentially exit the system altogether, if high fixed charges are approved and the utility's cost of service increases.[19]

The Company's proposed monthly charge proposals for residential and small commercial customers is bad for customers, policy, competitive providers, and even itself. It puts the Company's revenue recovery strategies in opposition to the best interests of its customers, which should be an unsustainable posture in an increasingly competitive sector. In my opinion, fixed charge proposals like those put forth by the Company in this case harm customers in several ways, violate fundamental principles of rate design, are unsupported by sound argument, and are inconsistent with regulatory trends around the country.

III. THE COMPANY'S PROPOSAL FOR A NEW DISTRIBUTED GENERATION RIDER 18 AND AN INFLOW/OUTFLOW DISTRIBUTED GENERATION TARIFF

[18] Peter Kind, "Pathway to a 21st Century Utility," CERES (Nov. 9, 2015), at p. 12.
[19] *Id.* at 30.

Overview of the Company's Rider 18 Proposal

Q. Please summarize the Company's Rider 18 proposal.

A. The Company proposes Rider 18 as a replacement tariff for net metering or distributed generation ("DG") customers, purportedly under the provisions of 6 PA 341 § 6a.(14).[20] The Company proposal has three major components. First, the Company proposes to charge DG customers for energy consumed as recorded on the consumption channel of the meter ("inflow") according to the customer's otherwise-applicable retail service rate. Second, the Company proposes a lost sales charge that it calls a System Access Contribution ("SAC") charge for distributed generation customers whose underlying rate does not include a demand charge, collected based on the customer's installed distributed generation capacity. The proposed SAC charge is $2.31 per kW per month of installed generation capacity for residential customers, and $2.28 per kW per month of installed capacity for small commercial customers.[21] Third, the Company proposes to provide credits to customers for metered generation outflow at the local node monthly average locational marginal price ("LMP"). The tariff provides for no monthly netting of consumption and generation as contemplated for distributed generation programs under Act 342 Part 5.[22]

Q. Under what authority does the Company propose its new tariff for DG customers?

A. The Company asserts that its proposal complies with provisions of Act 342,[23] and with the Commission's April 18, 2018 order in Case No. U-18383.[24]

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[20] *See* Dennis at p. 19, et seq.
[21] Exh. A-16, Sched. F9.
[22] 2016 PA 342, MCL 460.1173-1185.
[23] *See* Serna direct testimony at p. 66:1-10.
[24] *In re Commission's own motion, to implement the provisions of Sections 73 and 183(1) of 2016 PA 342 and Section 6a(14) of 2016 PA 341,* Case No. U-18383, Order (April 18, 2018).

Q. What did the Commission's April 18, 2018 order in Case No. U-18383 require?

A. On April 18, 2018, in Case No. U-18383, the Commission that, "in any rate case filed after June 1, 2018, the rate-regulated utility must file the Inflow/Outflow tariff, attached to this order as Exhibit A. The rate-regulated utility may also file its own distributed generation tariff, if desired."[25]

Q. What does Michigan law require regarding the Company's proposed tariff for distributed generation interconnected to the grid and operated by residential and small commercial customers?

A. Michigan law on distributed generation is complex. Table KRR-1 below summarizes the different structural, credit, and charges under True Net Metering, Modified Net Metering, and the Inflow / Outflow tariff models. As a matter of foundational principle, MCL § 460.6a. requires tariffs adopted under that statute be based on "equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program."[26] That is, it provides for a charge specifically for customers taking service under the net metering and distributed generation programs, not an alternative to such programs.

The distributed generation program was adopted through Act 342, which replaced the prior net metering program but contains many similar provisions. Act 342 states that its purpose is "to promote the development and use of clean and renewable energy resources," and "to diversify the resources used to reliably meet the energy needs of consumers," and to "[e]ncourage private investment in renewable energy."[27] Company

[25] *Id.* at p. 18.
[26] MCL 460.6a.(14).
[27] MCL 460.1001(2).

witness Serna also offers some non-legal interpretations of the requirements of Act 342 in his testimony[28] that I will address in greater detail later in this testimony.

[28] Serna direct at p. 49:19-24; p. 65:3-20.

Table 1 – Comparison of DG Tariff Structures

			Inflow / Outflow	
	True Net Metering (</= 20 kW)	**Modified Net Metering (> 20 kW)**	**Commission Order & Staff Proposal in U-18383**	**DTE Proposal**
Netting	Billing Period or TOU Period	Billing Period or TOU Period	None. 2-channel metering	None. 2-channel metering
Consumption that Can be Offset by Generation	All Consumption during the Billing/Charging Period	All Consumption during the Billing/Charging Period	Only Consumption Instantaneously Served by Generation	Only Consumption Instantaneously Served by Generation
Crediting Method	Monthly consumption minus monthly generation in kWh. Credit carryover to next month.	Monthly consumption minus monthly generation in kWh. Credit carryover to next month.	None. Bill nets charges and credits	None. Bill nets charges and credits
Limits on Credit Carryover	Max credit in next bill cannot exceed power supply charges in next bill, per 177(4). Month-to-month credit carryover not limited.	Max credit in next bill cannot exceed power supply charges in next bill, per 177(4). Month-to-month credit carryover not limited.	N/A	N/A
Credit Rate for Excess	Sec. 13 says retail and that Sec. 177(4) applies. Sec. 177(4) reduces credit from full retail, to LMP or Power Supply Rate	Sec. 7 says power suppy rate and that Sec. 177(4) applies. Sec. 177(4) reduces credit from full retail, to LMP or Power Supply Rate.	No netting means no excess.	No netting means no excess.
Effective Rate for Production	Full retail for all kWh up to consumption level with the month; then 177(4) credit carryover rules for excess.	Full retail for all kWh up to consumption level with the month; then 177(4) credit carryover rules for excess.	A fair valuation method for DG resources injected into the grid by DG customers consists of two parts: (1) an avoided capital and energy cost; and (2) all other avoided cost or benefit elements such as avoided distribution line losses, transmission and distribution costs, avoided air emission and environmental costs, the solar-fuel price hedge, and reactive supply and voltage control - Commission Staff Report, U-18383; and MCL 460.6a. Indicates that rate to be set in rate case after 6/1/2018.	LMP
Additional charges	MCL 460.6a(14) provides for "an appropriate tariff reflecting equitable cost of service for utility revenue requirements" applied to customers taking service under net metering or distributed generation programs, which includes true net metering.	Under Act 342 sec. 7, a "Standby charge" may be set at retail distrbution charge based on imputed usage. Imputed usage = consumption offset with generation (metered production minus monthly net flow). For demand charge rates, PSC must establish standby charge that provides equivalent contribution to the utility system. Act 342, sec. 7, which defines Modified Net Metering, implies that charges may be imposed for net metering and distributed generation customers under MCL 460.6a. Such charges would arguably be part of "an appropriate tariff reflecting equitable cost of service for utility revenue requirements" under 460.6a.(14). The language about such charges does not appear in the definition of True Net Metering.	None proposed.	System Access Contribution per-kW DG charge for non-demand rate customers based on lost sales difference between hypothetical solar customer and hypothetical non-solar customer.
Metering Requirements	Usage must be based on metered data. For systems greater than 20 kW, bidirectional flow meters are required.	Usage must be based on metered data. For systems greater than 20 kW, bidirectional flow meters are required.		

Q. What is your overall assessment of the Company's proposed DG tariff as it impacts residential and small commercial customers?

A. The Company's proposal fails to meet the requirements of Michigan law because it is not based on equitable cost of service and because it is discriminatory and unreasonable in its treatment of DG customers.

Q. Are you offering an opinion about the legality of the Commission's order in Case No. U-18383 adopting the Inflow/Outflow structure in place of netting?

A. No. I understand that there are disagreements about the relationship between the MCL 460.6a tariff and the distributed generation tariffs under Part 5 of Public Act 342. I also understand that there is no final decision in the U-18383 docket, and therefore there has been no opportunity for court review, because of a pending petition request for reconsideration. I am not providing an opinion about those legal issues.

Q. Does the Company's proposal meet the Commission's requirements as set out in its April 18, 2018 order in Case No. U-18383?

A. The Company's DG tariff proposal complies with the procedural requirement set out in the Commission's April 18, 2018 Order in Case No. U-18383 to the extent that it filed a DG tariff structured around the so-called "Inflow/Outflow" approach recommended by Staff and endorsed by the Commission in Case No. U-18383. However, the Company also filed and prefers an alternative proposal in Rider 18 that diverges from the Inflow/Outflow approach contemplated by the Staff's proposal in Case No. U-18383 and contains fundamental substantive flaws that should preclude it from being approved.

Q. What is the economic effect of the proposed tariff on residential and small commercial DG customers?

A. The Company did not prepare a bill impact analysis for proposed Rider 18. However, in response to a discovery request, the Company did provide sample data for five DG customers, with an average of 4.7 kW of installed DG.[29] Those sample data are provided in Table 2, below, which shows the dramatic increase in charges and reduction in savings that these DG customer experience on average. For these customers, on average, the Company proposal represents a more than 100% increase in charges levied on DG customers and reduces monthly savings by about $44 dollars per month. While impacts ultimately depend on customer energy use and DG production, over a 25-year estimated life for a solar customer, this difference amounts to a reduction in savings of more than $13,000. For a customer with a 4.7 kilowatt generation system, the Company's proposed SAC charge adds $3,216 in charges over the 25 years, or $10.72 per month, for the DG customer. Assuming an after-tax cost of going solar in 2018 of around $2.77,[30] the savings reductions and additional SAC charges proposed by the Company more than double a customer's cost for going solar.[31] The Company's proposed SAC charge in particular is devoid of any reasonable connection to the cost of service. The Company's inflow charge and outflow credit proposals are also flawed and unreasonable. Overall, I view the Company's proposal as confiscatory.

Q. Why do you use the word "confiscatory?"

A. While the impacts of the Company proposals will vary with customer levels of usage and DG generation, and with prices, the pattern revealed in the Company's own data from five sample customers, and summarized in Table 2, is that the proposed Rider 18 terms will

[29] Exhibit MEC-22, discovery response ELPCDE 2-84.
[30] https://news.energysage.com/how-much-does-the-average-solar-panel-installation-cost-in-the-u-s/
[31] Calculated as ($13,000 + $3,216) / 4.7 kW = $3.450 per watt.

reduce the benefits of self-generation by more than 60%.[32] For the reasons set out in this testimony, this level of tax on private customer investments in DG is excessive and unreasonable, and therefore, if approved would be confiscatory.

Table 2: Impact of Company Rider 18 Proposal on Sample Residential Customers

	Average Monthly Bill	Increase (Decrease) in Monthly Bill Compared to No DG	Percent Savings Compared to No DG	Increase in Charges Compared to Current Net Metering	Percent Increase in Charges Compared to Net Metering	Additional Cost / Lost Value over 25 years Compared to Net Metering
No DG	$111.95	$0.00	0%	$71.24	175%	$ 21,373
Inflow / Outflow, LMP $0.035 & SAC	$84.79	($27.15)	-24%	$44.09	108%	$ 13,228
Inflow / Outflow - LMP Outflow $0.035	$73.40	($38.55)	-34%	$32.70	80%	$ 9,810
Cat 1 - Current Net Metering Program	$40.70	($71.24)	-64%	$0.00	0%	

Q. What are the major drivers in reduction of value and increase of costs for DG customers under the Company's proposed Rider 18?

A. As Table KRR-2 makes clear, the Inflow / Outflow method is itself the major driver of value reduction when outflow is set at the monthly average LMP value, accounting for nearly three quarters (74%) of the reduced value.[33] The SAC reduces the value of DG by adding the remaining 26% of lost value in the form of a charge under the Company's proposal.

Q. What are your primary concerns with the Company's justification for the Rate Rider 18 provisions?

A. Witness Serna's testimony on the solar rate design reads like anti-solar advocacy, rather than substantive evidence. It is short on facts, long on unsubstantiated assertions, and unsupported by primary data. The most serious flaws in the Company's Rider 18 proposal are the way the Company unreasonably and selectively seeks interprets the provisions of

[32] Calculated as $44.09 / $71.24 = 62%.
[33] Calculated as $9,810 / $13,228 = 74.2%.

Public Acts 341 and 342 to propose the elimination of true net metering and modified net metering in favor of an Inflow / Outflow tariff that: (1) fails to provide a cost of service justification for the proposed inflow charge, (2) proposes a charge that resembles a stand-by, back-up, or supplementary power service charge without a reasonable relationship to the costs to serve DG customers; (3) includes an outflow credit value that fails to reflect the full avoided costs and benefits of exported DG electricity; and (4) adds a forfeiture provision that confiscates earned DG customer outflow credit value when a customer terminates participation in the DG program. This testimony addresses these issues serially, and in the same order that they are proposed in Company testimony.

The Company's Proposed Inflow Rate Based on Underlying Class Rates

Q. What is the Company's inflow charge proposal under its Rider 18 proposal?

A. The Company proposes to charge small DG customers for their inflow usage at the level of their standard retail rate for consumption. The Company also proposes to impose a System Access Contribution ("SAC") charge, discussed in the following section of this testimony.

Q. Is the Company proposal the same as that by the Staff in its February 21, 2018 report ("Staff Report") proposing the use of the Inflow / Outflow tariff model?[34]

A. Because of differences in terminology, it is not entirely clear whether the Company proposal is congruent with the Staff Report. The Staff Report speaks in terms of cost of service allocators and billing determinants, and states that "separate and distinct rate-schedules for DG customers are not needed,"[35] implying that all rates used in rate schedules

[34] MPSC Staff, *"Report on the MPSC Staff Study to Develop a Cost of Service-Based Distribution Generation Program Tariff,"* MPSC Case No. U-18383 (Feb. 21, 2018), at p. 12.
[35] *Id.*

for customers without DG would be used to calculate the inflow charge under the Staff proposal. The formula used in the Staff Report identifies both energy (kWh) and demand (kW) "Distribution & Power Supply" elements of the inflow charge. The Company proposes a charge "equivalent to the standard, full service retail rates for the underlying rate schedule."[36] Because the Company insists that its proposal is an "equivalent to," rather than simply applying, the full-service retail rate it is not clear that the Company is actually proposing to apply the retail rate.

Q. Notwithstanding potential differences in the Staff and Company approaches relating to the proposed inflow charge, are the otherwise applicable class rates for consumption of energy and demand a reasonable basis for inflow charges?

A. I cannot reach a conclusion as to the reasonableness of using the otherwise applicable class rates as the inflow charge without more information, particularly about the usage patterns of individual DG customers or even DG customers in aggregate.

Solar DG customers in particular have generation profiles that are very coincident with utility system peaks and pre-peaks. These customers have their own non-coincident peaks that provide diversification and asset utilization benefits to the system as a whole.[37] And the excess energy exported from a DG facility immediately travels through a revenue meter to serve load, generate utility billings, and avoid costs extending throughout the utility system.[38] All these factors point to the potential for significantly lower costs to serve DG customers than similar non-DG customers. It is likely a *credit* is in order for DG customers that reflects this *lower cost of service*, and that an inflow rate based on the costs

[36] Serna direct at p. 58:20-21.
[37] The Company has conducted no study of the benefits of DG to the system. *See* Company response to ELPC 1.24g Exhibit MEC-23.
[38] *See* Company responses to ELPC 1.24b & 1.24c Exhibit MEC-23.

associated with serving non-DG customers would be too high. I understand that other witnesses may be providing evidence related to the cost to serve DG customers. I reserve the right to respond to that evidence.

Q. Did the Company provide any evidence to support a finding that the costs of serving DG customers are equivalent to the costs of serving non-DG customers in the same rate class?

A. The sole basis offered by the Company for setting the inflow charge based on the DG customers' underlying consumption rates is the somewhat ambiguous declaration that "the volumetric retail rates in [the Company's] residential, and some of the secondary commercial rate schedules, captures the entire cost of service not supported by the customer charge."[39] For these reasons, further analysis is required before it can be concluded that the Company's proposed inflow charge in Rider 18 is just and reasonable.

The Company's Proposed System Access Contribution ("SAC") Charge

Q. What are your concerns with the Company's proposed SAC charge in Rider 18?

A. There are two major flaws with the Company's SAC charge proposal: How it works, and how it was constructed. First, the SAC imposes a charge on customers for what is essentially supplementary power service (and perhaps also back-up power service) that is not cost-based. Second, the SAC charge is constructed to impose a charge on DG customers for the energy not used by a hypothetical customer with a hypothetical DG facility and a hypothetical pattern of electricity usage, which is then allocated based on system capacity rather than energy usage (real or hypothetical).[40] As a result, the SAC charge is based on

[39] Serna at p. 59:5-7.
[40] *See* Exhibit MEC-24, Company discovery response MECNRDCSCDE-1.17d. *See also* Exhibit MEC-25, Company response to MECNRDCSC-3.4a, "on an overall basis (using 2017 data as a proxy for future loads), the System Access

the flawed premises that *non-use* of grid-supplied energy creates a basis for a charge under cost-based regulation, and that charges on self-generators should be based on sub-group deviations from forecasted usage which are then imposed on nameplate capacity rather than usage.

Q. Please explain how cost of service rate making principles inform evaluation of the Company's proposed SAC charge.

A. A fundamental principle of cost of service regulation is that a utility must enjoy a reasonable opportunity to recover the prudently incurred costs associated with the provision of electric service. And because the monopoly utility stands in a position of immense market power over small customers, the rates it charges must be based on the costs associated with services used by customers. It is therefore also axiomatic that under tariffed rates, a customer can only be required to pay for services that they actually use. In seeking regulatory approval to charge and collect rates, utilities have the legal responsibility of producing competent evidence of the costs incurred and of proving that the rates charged are reasonable, just, and not unduly discriminatory. The Company has not based the proposed SAC charge in Rider 18 on actual costs that is has incurred or will incur in providing services specifically to distributed generation customers.[41] Therefore, the Company fails in meeting its burdens under Michigan law.

Contribution charge when combined with the inflow charge, is designed to recover the distribution revenue if no electricity was consumed with behind the meter generation, however, impacts on customers would vary."

[41] *See* Exhibit MEC-26, Company response to MECNRDCSCDE-3.9, "The Company did not undertake a review or study any connection and/or correlation between an individual distributed generation customer's nameplate system capacity and his or her contribution to peak loads, energy, and customer counts."

Q. Are there statutory and regulatory provisions, in addition to general requirements that rates be just and reasonable, that guide the review of the Company's proposed SAC charge?

A. Yes. MCL 460.6a. requires that a tariff related to a distributed generation program be based on "equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program."[42] Act 342 states that its purpose is "to promote the development and use of clean and renewable energy resources," and "to diversify the resources used to reliably meet the energy needs of consumers," and to "[e]ncourage private investment in renewable energy . . ."[43] Further, because small distributed solar generation facilities are also qualifying facilities under federal and Michigan law, additional state and federal laws apply. The federal Public Utility Regulatory Policies Act[44] requires utilities to interconnect "small power production facilities" as defined by FERC eligibility requirements for qualifying facilities ("QFs").[45] QF status automatically applies to on-site solar generators up to 1 MW.[46] FERC's regulations implementing PURPA require that rates for electricity sales to QFs "shall be just and reasonable and in the public interest" and "[s]hall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility."[47] Under FERC's regulations, rates for QFs that differ from the rates otherwise applicable to non-QF customers are only considered to be non-discriminatory when they are "based on accurate data and consistent system-wide costing principles" and only "to

[42] MCL 460.6a.(14).
[43] MCL 460.1001(2).
[44] 16 USC Ch. 46.
[45] 18 C.F.R. § 292.303(c).
[46] Facilities with net power production of less than 1 MW are exempt from the QF certification process. 18 C.F.R. § 292.203(d).
[47] 18 CFR § 292.305(a)(1)(ii).

the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[48] MCL 460.6v imposes nearly identical requirements on the Company and Commission-approved rates relating to just and reasonable rates, non-discrimination, and sales to qualifying facilities.[49]

Q. Does the proposed SAC charge comply with these statutory and regulatory requirements?

A. No. The Company can only impose additive charges on any self-generating customer, which must be based on actual costs of providing service as determined through methodologies applied to all customers regardless of whether they self-generate. The SAC fails under those standards.

The Company states that DG customers seek service "to meet their energy needs when the generation is not operating at full output or when there are additional demand that solar cannot meet."[50] The Company is describing supplementary power service and perhaps, back-up power service. A charge for supplementary service is appropriate for service above and beyond what the DG customer provides for themselves with their own equipment in order to meet their needs.[51] The Company has not created a cost-based rate for supplementary service with its class-based rate, and has not demonstrated in this case that the Company has incurred any costs relating to the provision of such service that are additional to those reflected in class rates.[52] As shown in witness Serna's testimony at

[48] 18 CFR § 292.305(a)(2).
[49] *See* MCL 460.6v.(4).
[50] Serna direct at p. 51:8-13
[51] MCL 460.6v.(6)(f): "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to the electric energy or capacity that the qualifying facility generates.
[52] *See* Company response to ELPC 1.23 Exhibit MEC-17, stating that the Company has not conducted a cost of service study unique to DG customers. In Company Response to ELPC 1.24a, Exhibit MEC-23, the Company states that it "has not developed or reviewed documentation of the impacts of distributed generation customers on the Company's system."

Figure 1[53] the pattern of solar DG customer production and load shows a dramatic reduction in net load during the hours leading up to and including a typical summer peak, implying cost savings result from DG operations. The Company confirm this effect.[54] Whether through net metering or an Inflow / Outflow method, the Company must also account for the full range of benefits and avoided costs created by exported distributed generation, and for the fact that exported energy physically serves and is fully metered at the nearest unserved electric load, in order to establish a just and reasonable rate for supplementary service.

A lawful charge for back-up power service must be based on costs the Company incurs when the solar customer's generation is not operating as it ordinarily would.[55] A back-up power service charge should, therefore, be based on demonstrated incremental costs incurred and directly associated with provision of service during actual or statistically demonstrated periods of unscheduled outages at the DG facility. In this regard, it is essential that the Company not confuse variability with intermittence. Variability in output due to changes in solar insolation is predictable, and solar modeling tools account for the resulting variability in solar output well. Intermittence relates to unexpected reductions in availability; solar generation has availability factors in the range of 95% and greater. Due to the size of rooftop solar generation and the fact that it is disbursed across the Company's system, the 5% of unavailability of solar is not perceptible in the diversity of all other loads.

[53] Serna at p. 52.
[54] Company Response to MECNRDCSCDE-1.10a, Exhibit MEC-27, confirming that DG customers have lower average contribution to class demands during the class NCP hours used to allocate distribution system capacity costs than non-DG customers in the same class. *See also,* Company Response to MECNRDCSCDE-3.6a, Exhibit MEC-30 "The Company does not "contend that installing distributed generation reduces a customer's contribution to 4CP, 12CP, and NCP class loads by a smaller amount than the distributed generation reduces kWh inflows."
[55] MCL 460.6v.(6)(b): "Backup power" means electric energy or capacity supplied by an electric utility to replace electric energy ordinarily generated by a qualifying facility's own electric generation equipment during an unscheduled outage of the qualifying facility.

A calculation of cost to provide standby service to rooftop solar would therefore result in a value of zero or near zero. However, the Company did not do a cost-based calculation for standby service. Instead of relying on cost-based data, the Company built its proposed Rider 18 rates to be a revenue recovery mechanism based on the hypothetical bills that the customers with generation *would have paid if they had never invested in solar generation*. That is, the proposed charge is based on the reduction in revenue that results from customers' reduced demand for services, not on additional services required after solar generation is installed. Therefore, it is not cost based. The SAC charge is unjust, unreasonable, contrary to Michigan law, and contrary to federal law as well.

Q. Doesn't Company witness Serna offer evidence that distributed generation customers have a summer net peak demand nearly half a kW greater than traditional residential Rate D1 customers?[56]

A. Company witness Serna's assertion about the respective summer net peak demand of DG customers as compared to non-DG customers is a deceptive half-truth. Mr. Serna's comment and the associated data that he cites[57] purport to shows that for some undefined sets of DG and non-DG customers, there is an average value for "Maximum Hourly Average Peak" that is about 0.5 kW higher for the net metered customers. What Mr. Serna omits in his testimony—and does not offer in support of the Company's rate proposal—is the DG customers' share of cumulative demand on the system, at the substation level, or at the feeder level, *during peak hours that drive costs*. The data do not tell us whether the DG summer peak demand is coincident with system peak demand, or whether it shifts DG customers' maximum demands to off-peak hours, providing peak load reduction, load

[56] Serna direct at 53:1-3.
[57] *See* Exh. A-16, Sch. F11.

diversification, and asset utilization benefits. The data Mr. Serna relies on, therefore, say nothing about the relative cost to serve. Nor do the data tell us whether purported difference in individual customer peak load has anything to do with the fact that the customer has distributed generation or whether it is due to independent and unrelated factors. The data may simply be an artifact of the fact that larger, higher-use, and higher-earning customers were the first investors in DG, especially in very small markets like the one that exists in the Company's service territory. In sum, the data Mr. Serna presents tell us nothing about cost to serve DG customers that are different than costs to serve customers without generation. The statement from witness Serna has no probative value in supporting the Company proposal.

Q. Doesn't Company witness Serna also assert that DG customers place a demand on the Company for several kinds of additional services simply as a result of the installation and operation of distributed generation?

A. In general, witness Serna makes the assertion that the "bidirectional relationship between the distribution system and distributed generation customers is a key and fundamental distinction of these customers from traditional customers."[58] That is, at most,[59] a tautology. It is not a difference based on cost, which is what the applicable statutes and regulations require to support a different treatment of customer-generators. Mr. Serna provides no cost-based difference between self-generating and non-generating customers.

Mr. Serna also asserts that the Company provides DG customers with a "range of additional grid services from the electric system that are unique to their choice to utilize

[58] Serna direct at p. 52:8-11.

[59] Not all customers who self-generate export electricity. Therefore, it is not even true that distributed generation customers necessarily have "a bidirectional relationship with the distribution grid."

distributed generation,"[60] and incurs costs resulting from "operational and technical impacts of distributed generation"[61] relating to system protective equipment impacts or reverse power flows that are not already addressed through compliance with existing safety and interconnection standards. However, these assertions are false and unsubstantiated.[62] First, the services that Mr. Serna identifies—capacity to meet demand, balancing services and inrush current to start large appliances[63]—are services that are provided as part of the bundled service received by all customers. They are not "additional grid services" to only distributed generation customers. Second, despite claiming additional costs from distributed generation customers' "unique electric system dynamics," the Company admits that it has no evidence of any actual impacts much less costs.[64] Thus, here again, the Company provides no cost-based evidence to support a charge for these "services" or for the "impacts" that DG might cause.

Q. Do you agree with Witness Serna's assertions that system costs are stable and predictable except for distributed generation[65] and that DG customers enjoy "system use optionality" but are "not supporting the costs of the infrastructure required for their service?"[66]

A. These arguments by Mr. Serna are also misleading, incomplete, and unsubstantiated. First, the Company makes no evidentiary showing that system costs are stable and predictable without distributed generation, and that these costs are being made unstable and

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[60] Serna direct at p. 51:6-8.
[61] *Id* at p. 53:5-20.
[62] Witness Serna asserts at p. 53:13, that distributed generation "may cause the circuit to trip offline," but confirms in Company Response to MECNRDCSCDE-1.2 (Revised) Exhibit MEC-28 that there is no evidence of any instance of this happening.
[63] Serna at 51:8-13.
[64] DTE Response to MECNRDCSC-1.2 (Revised), Exhibit MEC-28.
[65] Serna direct at p. 60:5-14.
[66] *Id.*

unpredictable as a result of distributed generation. An honest analysis of distribution system investment requirements shows that grid modernization, weather, maintenance, and other factors have a much more significant and variable impact on distribution system costs than distributed generation. Hundreds of DG systems are operating in an interconnected manner on the Company's grid today, and the Company has not pointed to any instability- or unpredictability-induced impacts, trends, data, or costs.[67]

Second, witness Serna's implication that DG customers enjoy a special or unique kind of "optionality" with regard to their use of the grid is baseless. Optionality is a bargained-for contractual right by all residential and general service customers that can be volitionally exercised by any of them at any time. DG customers enjoy no such rights that are materially different from those that any other customer enjoys. Just like the customer that invests in a high-efficiency heating and cooling system, the DG customer has taken private action to reduce use. Moreover, the customer with 5 kW of rooftop solar who may take (and pay for) 5 kW of service from the Company should the rooftop solar trip offline is exercising the same "optionality" of service as the customer with an electric vehicle who may, at any time, plug that vehicle in to charge at 5 kW. This optionality is not a different service that could justify discriminatory treatment or charges not related meaningfully to increased costs.

Furthermore, characterization of electric service as an "option" is inconsistent with the understood meaning of that term. DG customers do take service under net metering tariffs, but are not equivalent to the typically understood meaning of an "option." DG customers with solar do not arbitrage against market prices or distribution system costs.

[67] *See* Company response to MECNRDCSCDE-1.2 Revised, Exhibit MEC-28.

And DG customers are not able to reasonably negotiate an option with a monopoly actor like DTE.

Finally, Mr. Serna's assertion that DG customers are not supporting the infrastructure costs required to serve them is an objectively provable assertion. However, Mr. Serna offers no proof for the assertion. Nor does the Company offer any evidence that DG customers fail to pay costs they cause in a manner different than any other customer who reduces their load through technology or behavior. Due to solar's production coincident with many of the hours used to allocate costs in the cost of service studies the utility conducted, I would expect a cost of service study conducted for solar DG customers to show a much lower cost to serve those customers. Given witness Serna's broadside assertions about DG customers, the fact that the Company elected not to attempt to show that DG customers under-collect their cost of service with data is telling. Moreover, the fact that the Company choose to construct its SAC charge based on lost sales, rather than costs of service, is also telling. There is no evidence that DG customers under collect their costs.

Q. Witness Serna asserts that the SAC charge is specifically designed to recover two kinds of electric system costs related to (1) DG intermittence and variability, and (2) the requirement for "in rush" power service. Are these services properly costed in the SAC charge?[68]

A. No. The costs that witness Serna alleges are related to intermittence and variability, and in-rush power, cannot be reflected directly or accurately in the SAC charge because these costs, even if they existed, are unrelated to the calculations used to develop the SAC

[68] Serna at p. 61:1 through p. 62:2.

charge.[69] As noted above, the SAC is designed to recover lost revenue from services not provided to DG customers, not based on the intermittence and variability or in-rush current of service actually provided. Moreover, there is no evidence that DG customers show significantly different levels of variability or demand for in-rush service as compared to the universe of Rate D1 and Rate D3 customers. Given the very high rates of availability for DG facilities, the very small number of DG customers on the Company system, and the fact that net meted customers pay the fully-loaded retail rate when their facilities fail to operate as forecasted, it is not likely that the Company *could* show material costs related to DG intermittence, even if they had tried. The SAC charge is therefore specifically unjustified by the costs that witness Serna asserts as the justification for the charge.

Even if Mr. Serna is attempting to assert that the SAC recovers the cost of DG customers' variability and inrush current because it recovers amounts based on the distribution rate for D1 and D3 customers—which includes costs associated with addressing variations in demand and to meet demand for in-rush service—he is incorrect. DG customers already pay the fully bundled distribution rate for inflows and, therefore, recover whatever costs for variability in demand and inrush current are bundled into that rate. The SAC charges the fully bundled rate for service the utility *does not provide*.

Q. Please explain why you say the SAC is based on the bill a hypothetical customer would have paid and why this is a problem.

A. Company Exhibit A-16, Schedule F9, sponsored by Company witness Dennis under the direction of Company witness Serna, shows how the Company built its proposed SAC charge. The Company first averages all the inflow, outflow, and generation for distributed

[69] *See* Company response to MECNRDCSCDE-1.11 Exhibit MEC-29 (Company has no data relating to the costs of providing in-rush current.).

generation customers during the year 2017. From those data, the Company calculates the average total on-site usage for these customers. The Company then multiplies these values times the per-kWh revenue requirement for all DG and non-DG customers in rate classes D1 and D3. It is important to note that the Company does not have or rely upon cost-of-service values specific to DG customers within those classes. The Company then calculates the amount of revenues it would not recover from the average DG customer due to the average amount of reduced sales to those customers, calling this a "revenue deficiency." Finally, the Company assumes that the average customer has an average-sized solar system with a capacity of 6.7 kW and divides the hypothetical "revenue deficiency" into this hypothetical system size to arrive at a value of $2.31 and $2.28 per kW that it wants to charge DG customers in rate classes D1 and D3 respectively.

There are three important points to note from this calculation. First, it is not based on a cost of service specific to DG customers and their loads. Instead, it uses the revenue requirement for the broad class of primarily non-DG customers. Second, it calculates the amount of revenue it is not receiving because of reduced units of fully-bundled distribution service no longer required by the customer who is serving her load from behind the meter generation. Third, it redistributes that lost revenue to individual customers based on each customer's nameplate capacity of generation regardless of that customer's usage. Each of these points, alone, would make the SAC not cost based.

Q. Does the Company offer any explanation or justification for its reliance on average data for DG customers as a basis for building the SAC charge?

A. Company witness Serna asserts that the SAC charge "assigns a cost per kW AC of nameplate system capacity based on the system-cost responsibility of distributed

generation customers."[70] Company witness Dennis appears to try to justify the use of averaged data when he states that "the Company in this case (and in past cases) is moving toward universal consumption based (kWh) distribution charges for all residential secondary customers, and for all commercial secondary customers with a per kWh distribution charge."[71]

Q. Do average-based calculations accurately capture system-cost responsibility of individual distribution generation customers?

A. No. Witness Serna's statement is misleading and incomplete when he asserts that the SAC charge is based on "system-cost responsibility of distributed generation customers." The statement is not true when applied to the costs created by DG customers as a whole or individual DG customers specifically. As demonstrated above, the SAC charge is not based on costs incurred to serve DG customers as a subclass. Even if it was, the charge is still not cost-based because it is unrelated to usage or generation of individual customers. A 5-kW DG customer that is a high-volume, on-peak, no-export user of electricity would be required to pay exactly the same SAC charge as a 5-kW DG customer with low usage, and minimal use and high exports during the system peak. This outcome is not cost-based and not based on the use of the electric grid.[72]

Q. Is a "universal distribution charge" approach a reasonable justification for the approach used by the Company in building its proposed SAC charge?

A. Absolutely not. As already explained, the SAC charge can only be justified by a demonstration of incremental costs incurred by the Company to provide incremental

[70] Serna direct at p. 59:24-25.
[71] Dennis direct at p. 20:21-24.
[72] MCL 460.11(1).

services, like supplementary power or back-up power service, that are not covered by charges incurred when a DG customer is a net consumer of energy from the grid and pays applicable cost-based class rates under Rates D1 and D3.

Q. Is the SAC charge deficient in other ways?

A. To the extent that the Company is proposing the SAC charge as a kind of charge for back-up power service, it violates established federal regulations that state that "the rate for sales of back-up power . . . shall not be based on an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both . . ."[73] The lost-sales approach used by the Company calculates the SAC charge based on the assumption that all DG facilities, regardless of actual and individual performance reduce utility sales by the full amount of DG load reduction. It further assumes that all of this loss of sales must be recovered from all DG customers as if they were all calling on the Company for back-up or supplementary service at the same time and potentially during system or class peaks.

Q. Why do you cite federal regulations in your review of a proposed tariff for DG customers?

A. The federal Public Utility Regulatory Policies Act[74] requires utilities to interconnect "small power production facilities" as defined by FERC eligibility requirements for qualifying facilities ("QFs").[75] QF status automatically applies to on-site solar generators up to 1

[73] 18 CFR § 292.305.
[74] 16 USC Ch. 46.
[75] 18 C.F.R. § 292.303(c).

MW.[76] FERC's regulations implementing PURPA require that rates for electricity sales to QFs "shall be just and reasonable and in the public interest" and "[s]hall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility."[77] Under FERC's regulations, rates for QFs that differ from the rates otherwise applicable to non-QF customers are only considered non-discriminatory when they are "based on accurate data and consistent system-wide costing principles" and only "to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[78]

The Company's Proposed Outflow Rate based on the Monthly Average LMP

Q. How does the Company attempt to justify its proposal to compensate outflow energy at a rate equal to the monthly average LMP?

A. The Company makes the flawed assertion that energy exported from a DG facility "offsets only the fuel and purchased power component of the energy cost classification," and that exported energy "does not reduce the cost of the Company's distribution infrastructure [or of] the Company's generation capacity required to serve customer load when their generator is not producing," because these costs do not vary with volumetric energy consumption.[79]

Q. What is your evaluation of these assertions by the Company regarding the value and effect of exported energy from DG facilities.

[76] Facilities with net power production of less than 1 MW are exempt from the QF certification process. 18 C.F.R. § 292.203(d).
[77] 18 CFR § 292.305(a)(1)(ii).
[78] 18 CFR § 292.305(a)(2).
[79] Serna direct at p. 62:12-17.

A. The Company's approach to outflow credit is factually incorrect. Electricity produced by distributed generation is injected into the distribution grid at the distribution level, offsetting electricity that would have otherwise flowed across all upstream equipment (production, transmission, and most of the primary distribution system). That is, the exports appear as negative load upstream of the nearest unserved load and offset all costs driven by loads on all upstream equipment. Wholesale energy prices do not reflect the full range of costs avoided by that electricity exported to the secondary distribution grid.

Unlike wholesale energy, distributed generation exports do not require transmission services or suffer transmission losses. As a matter of physics, the excess energy serves the nearest unserved load and passes through a revenue meter from which the Company generates a bill at the full applicable retail rates. The full range of costs avoided by DG generation is the appropriate place to start in setting a fair compensation rate for excess DG generation. It is also consistent with how the Company views cost –causation for purposes of cost-allocation in the cost of service study. The Company's proposal to value exports at only wholesale energy is both illogical and wrong in its excessively narrow approach to valuing exported energy from DG facilities, is confiscatory, is discriminatory compared to how the Company views cost causation for its own purposes and is inconsistent with Michigan and federal law.

Q. Did the Company consider using an avoided cost method for setting the outflow credit rate under its proposed Rider 18?

A. The Company rejected an avoided cost basis for setting the outflow rate because future avoided costs were theoretical and based on costs that would be avoided in the future.[80]

[80] Serna direct at p. 64:11-14.

This approach stands in stark contrast to the Company's willingness to propose a SAC charge for all small DG customers based on the theoretical revenue differences of a single hypothetical DG and non-DG customer. The Company assertions about avoiding system costs also confuse sunk costs with fixed costs. A solar DG facility will generate at a very high availability factor and on a very predictable basis for decades—providing real capacity value and other resource values. The Company's primary problem seems to be that the benefits of DG facilities occur in the future and are measured by investments that the Company can avoid; and after the Company has already sunk excessive investments into fixed distribution facilities costs made less necessary as a result of DG facility generation.

Q. Does the Company have any special concerns about reflecting the capacity value of DG generation in its proposed outflow rate?

A. Yes. The Company offers the faulty proposition that a capacity credit is inappropriate because DG customers do not have a "temporal production contract" with the Company, and because the primary purpose of DG is the production of electricity for self-consumption.[81] First, a tariff is a contract, providing the precise terms under which credit will be awarded for energy, capacity, or any other value that accompanies excess DG production. Tariffs are different from the private contracts that the Company might otherwise seek to negotiate with DG customers, because they are subject to Commission oversight and therefore reduce the risk of discriminatory exercise of negotiating power by any one party. No additional contract is required with DG customers, nor would a contract change the fact of the generation profile of distributed generation. The Company's

[81] *See* Serna direct at p. 64:15-22.

assertion that a temporal production contract is a necessary precondition to recognizing the capacity value of DG unreasonably promotes form over substance. Second, the purposes for which DG customers install DG systems is absolutely irrelevant to whether the Company avoids having to procure and provide capacity services to that customer at a reduced level due to the DG generation. Moreover, the DG customer's motivations have nothing to do with the capacity value of exports. The Company's assertions that these customers "cannot be counted on to generate when needed" speaks to dispatchability, but not capacity. It is also not correct. Solar generation has high availability that can be predicted. While it will not be the nameplate capacity of the generating systems in each hour of the year, there will be a predictable generation value that can "be counted on to generate when needed"

Q. What is your opinion on the Company's assertion that excess DG generation does not reduce the costs of "the Company's generation capacity required to serve customer load when their generator is not producing."[82]

A. The Company position that the value of DG outflows should be limited to the LMP rate because those outflows do not have capacity value when they do not occur makes no logical sense. The outflow credit should reflect the value of excess DG generation, not non-production. The relevant question is how much solar *will* generate during the peak periods that drive capacity needs. Just like fossil generation experiences outages and derates and is not available at its nameplate capacity during all hours does not mean that it receives no capacity value; it receives capacity value based on the projected availability during peak hours. The outflow credit for DG solar should likewise reflect the extent to which the DG

[82] Serna direct at p. 62:15-16.

generation outflows reduce Company generation capacity costs when the DG generator is producing, and the fact that DG generation does not provide capacity value when that DG generation is not operating is not a justification for limiting the outflow credit to the LMP rate.

Q. The Company also asserts that DG electricity exports cannot reduce or offset costs associated with utility distribution or capacity costs because "these costs do not vary with volumetric energy consumption."[83] Is this a reasonable position?

A. The Company's ultimate position that distribution or capacity costs do not vary with volumetric energy consumption further reflects the Company's flawed confusion of sunk and fixed costs and ignores the reality of electricity system operations. Future distribution investments, the life of existing investments, the adequacy of existing capacity, and the need for future capacity, are driven by the level of both energy and demand. If enough customers use sufficient additional energy during relatively coincident times, the Company will see existing infrastructure wear out more quickly or become simply inadequate to serve demand. It therefore follows that *reductions* in volumetric consumption, whether due to conservation, more efficient use, self-generation, or the injection of electricity at the distribution level, can prolong the useful life of fixed cost investments, defer or avoid the need for future investments, and reduce capacity costs at the distribution, transmission, and generation level. The Company's assertion is also internally inconsistent. The Company allocates costs to the residential and small commercial classes based on demand during peak hours, and purports that such allocation follows cost-causation factors; it cannot

[83] Serna direct at p. 62:12-17.

simultaneously contend that negative load during those same peak hours has no negative cost impact.

Q. Is the Company proposal to compensate exported DG energy at the LMP rate consistent with the Inflow / Outflow tariff structure?

A. No. The market price for energy embodied in the LMP is an artifact of market operations, the bidding strategies of numerous market participants, the influence of tax incentives, and a structure designed to address very short-term congestion price conditions. The full cost of a utility resource, and hence, the full avoided cost that should be reflected in outflow rates—just like in PURPA rates—includes capital investment costs, portfolio requirements, long-run resource costs—all the costs associated with the purchase from the qualifying facility, but for that purchase, the utility would incur. Spot energy markets reflected in the LMP are not designed to reveal these costs. Full avoided cost does not equate to the *price* that the utility might pay to buy one kilowatt of energy in the market; it reflects the full panoply of *costs* that the utility avoided by not having to generate, transmit, and deliver that kilowatt itself.

Q. What kind of costs can be considered in establishing just and reasonable outflow and PURPA rates for sales to a utility?

A. The PURPA regulations lay out several factors that "shall, to the extent practicable, be taken into account" when state commissions are determining avoided costs.[84] The legal mandate that state commissions consider these factors underscores the fact that avoided costs are not simply marginal prices. That is, avoided costs must include all of the costs that the utility does not incur as a result of the purchase from the qualifying facility. Full

[84] 18 CFR § 292.101(e)

and fair consideration of these factors is essential to ensure that rates for DG customers are not unduly discriminatory, a principle embedded in both Michigan and federal law.[85] These factors include:

- Energy and capacity cost data provided pursuant to FERC regulations, including state review of any such data;
- Availability of capacity or energy from qualifying facilities during system daily and seasonal peak periods;
- Dispatchability and reliability;
- Duration and terms of contract;
- Usefulness of energy and capacity during system emergencies;
- Individual and aggregate value of energy and capacity;
- Smaller capacity increments and shorter lead times for additional capacity from qualifying facilities;
- Relationship of availability of energy and capacity from the qualifying facility to the ability of the utility to avoid costs, including deferral of capacity additions and reduction in fossil fuel use; and
- Costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility.[86]
- State commissions may also account for the environmental compliance and resource portfolio compliance costs "of all fuel sources" in determining avoided cost rates, as long as they are "real costs that would be incurred by utilities."[87] In other words,

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[85] *See* 18 CFR.304(a)(1) (rates for purchases); MCL § 460.6v.
[86] 18 CFR § 292.304(e)(4).
[87] 71 FERC 61,269, 62,080 (June 2, 1995) (citing 70 FERC 61,290, 61,676, reconsideration denied, 71 FERC 61,232 (1995)).

commissions may account for environmental costs that are part of the utility's cost of doing business to the extent those costs would be avoided by the purchase from the qualifying facility.

Q. Did the Commission Staff take a position on the proper valuation of outflows in its proposal that the Commission adopt the Inflow / Outflow model?

A. Yes. In its report to the Commission, the Staff stated that "[a] fair valuation method for DG resources injected into the grid by DG customers consists of two parts: (1) an avoided capital and energy cost; and (2) all other avoided cost or benefit elements such as avoided distribution line losses, transmission and distribution costs, avoided air emission and environmental costs, the solar-fuel price hedge, and reactive supply and voltage control."[88] In my opinion, and without expressing an opinion on the merits or legality of the Inflow / Outflow method in general, the Staff position on setting the outflow credit rates is a good place to start.

Q. The Company suggests that the LMP rate for outflow credits under the Inflow / Outflow tariff method is required by Act 342, particularly by section 177 of the Act.[89] Do you agree?

A. As an attorney with nearly 35 years of experience in law, including 28 years in utility regulatory law, I offer my personal opinion—but not a formal legal opinion—that the Company is cherry-picking language from the statute in order to support its position. First, I would note that the Commission addressed this very issue in its Order of April 18, 2018, in Case No. U-18383, when it concluded that section 177 of Act 342 does not apply to the

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[88] MPSC Staff, "Report on the MPSC Staff Study to Develop a Cost of Service-Based Distribution Generation Program Tariff," MPSC Case No. U-18383 (Feb. 21, 2018), at p. 15.
[89] Serna at p. 65:1-20.

charge rate or credit value established under a cost of service based tariff established under Act 341, section 6a.(14). In this case, unless and until a court intervenes, or the Commission revises its order in U-18383, the Company's obligation was to propose a just and reasonable tariff for DG customers based on the Commission's decision that section 177 does not apply and, therefore, cannot limit the outflow credit. Second, the Company's view that a portion of section 177(4) applies to limit the credit for exports conveniently ignores the fact that the rest of section 177, as well as the rest of Act 342 Part 5 it was adopted as part of, also retain true net metering for DG customers with systems 20 kilowatts or smaller in size. Therefore, in order to be consistent with itself, in addition to proposing to limit exports based on the second half of section 177(4) the Company should have also proposed to retain netting within the billing period as required by section 177 and Act 342 Part 5. The Company attempts to strip the second portion of 177(4) of its context and insists that it applies, while simultaneously insisting that the rest of the distributed generation program do not apply. That interpretation is untenable.

The Company's Proposed Confiscation of Credit Balances from Customers

Q. What is the Company's Rider 18 proposal regarding excess credits when a customer terminates participation in the program?

A. The Company proposes that a customer forfeits all unused credits when a customer terminates participation in the DG program.[90]

Q. Is this approach reasonable?

A. No. The Company proposal to confiscate all unused credits when a customer terminates participation in the DG program ignores the fact that customers earn those credits during

[90] Company proposed Rider 18, at D-116.00, Exhibit A-16, Sched. F10.

the period of their participation in the program, and that the credits represent excess energy that the Company used in providing electric service to customers.

Q. What do you recommend that the Commission require of the Company regarding unused credits when a customer terminates participation in the DG program?

A. Customers who terminate participation in the DG program should receive the full value of their remaining credits as a credit on their final bill. To the extent overpayments are refunded to other customers when they terminate service, the same should be true of DG customers who have overpayments because of export credits.

IV. CHARGING CUSTOMERS FOR EDISON ELECTRIC INSTITUTE ACTIVITIES

Q. Is the Company a member of any trade associations?

A. Yes, the Company is a member of several trade associations, including, in particular, the Edison Electric Institute ("EEI").[91]

Q. Please describe the issue of the Company seeking cost recovery from customers for EEI activities.

A. The Company seeks to recover EEI dues as an "above-the-line" expense from ratepayers. Unbeknownst to most customers, these payments may be used to fund advocacy with which customers may disagree and that is contrary to their interests. The Company reports that it paid a total of $1,269,000 in dues to EEI.[92] Groups such as EEI receive a majority of their revenue from utility membership dues,[93] are highly political in nature, and promote policies that are not always in the best interests of ratepayers.

[91] Exh. A-3, Sched. C14, line 4.
[92] *Id.*
[93] U.S. Dep't of Treasury, IRS, Form 990, Part VIII Statement of Revenue (Edison Electric Institute, 2015), https://projects.propublica.org/nonprofits/organizations/130659550.

The Company also indicates in this filing that it reduced the total amount of all corporate memberships charged to customers by $554,000 for "disallowed expense,"[94] and that some of the dues to EEI are "below the line," recorded in account 426.4 (relating to Political and Civil Activities) and are not charged to ratepayers.[95]

Q. How does the Company determine the amount of EEI dues that are not charged to ratepayers as Political and Civil Activities?

A. The Company takes EEI's word for it. The Company states that EEI identifies the portion of dues that relate to influencing legislation on the invoice that the association submits to the Company.[96] The Company provides no information to support the reasonableness of cost recovery for the "above the line" dues or to ensure the accuracy of the assertions by EEI as to the extent to which dues are used to support lobbying and advocacy positions.

Q. What do you conclude therefore about the Company's effort to have customers pay for EEI dues?

A. The Company has failed to demonstrate that the costs associated with EEI membership dues are limited to activities that benefit ratepayers and therefore are just and reasonable. The Company has failed to demonstrate that it has removed all payments for lobbying and other inappropriate activities from the costs it seeks to recover from customers. The Company produced no evidence that it verified the assertions from EEI.

Q. What do you recommend that the Commission do based on your findings?

[94] Exh. A-3, Sched. C14, line 14.
[95] Exhibit MEC-31 Company response to MECNRDCSCDE-3-16b.
[96] *Id.*

A. Based on this failure to justify and substantiate the reasonableness of cost recovery for the dues paid to EEI, I recommend that the Commission deny recovery of these expenses and order the Company to adjust its revenue requirement downward accordingly.

Q. What is EEI, and what services does the trade association provide to its members?

A. EEI is a trade association with a large operating budget ($96.5 million in 2016) that represents U.S. investor-owned electric companies in all 50 states.[97] EEI describes its mission as providing public policy leadership, industry data, business intelligence, conferences and forums, and products and services to the utility industry.[98] EEI also provides a Mutual Assistance Program in which member utilities can access assistance during storms to restore power to affected customers.[99] Most of EEI's work involves promoting its utility members' policy agenda and bottom-line through political action and advocacy.

Q. What portion of EEI's budget is spent on lobbying activity as compared with other activities?

A. It is unknown what portion of EEI's budget is allocated towards lobbying activity because, to my knowledge, the most recently available NARUC audit of EEI data is from 2005. The Company has not submitted a more recent audit of any kind in this proceeding.

Q. Why is it important to know how EEI treats its expenditures?

A. Reliable data on EEI spending activity is necessary for reasonable allocations of expenses between lobbying and non-lobbying activity. Absence of that data presents a significant

[97] Budget data based on EEI IRS Form 990 for 2016 obtained from Guidestar, available at https://www.guidestar.org/FinDocuments/2016/130/659/2016-130659550-0eb71f32-9O.pdf.
[98] *See* EEI, *About EEI*, http://www.eei.org/about/Pages/default.aspx (last visited May 24, 2018).
[99] *See* EEI, *Mutual Assistance*, http://www.eei.org/issuesandpolicy/electricreliability/mutual assistance/ (last visited May 24, 2018).

challenge for stakeholders, ratepayers, and regulatory authorities who seek to protect ratepayers from funding lobbying and any non-lobbying advocacy that may not be in their best interest.

Q. What dues-funded EEI activities are in the interest of Michigan ratepayers?

A. Examples of association activities clearly in the interests of ratepayers include: EEI sponsored workforce education and training modules, knowledge campaigns centered around electrical and gas safety, and EEI's Mutual Assistance Program that combines utility resources during extreme weather to restore power to customers.

Q. So, what is the problem with above-the-line trade association dues?

A. The problem is that the EEI acts as advocacy organizations in supporting a policy agenda contrary to many ratepayers' interests or personal beliefs, and contrary to the policies of the State of Michigan.

Q. Are you recommending that the Company not be allowed to indirectly fund ALEC or other anti-renewable energy advocacy organizations through its contributions to EEI member dues?

A. No. I accept that the Company may decide that it is in the best interests of shareholders to join in these agendas. My testimony is that ratepayers should not be required to support these organizations, directly or indirectly, through EEI dues, and that the Company must produce sufficient and competent evidence to the Commission that any dues payments that it seeks to recover from ratepayers through the revenue requirement do not fund these activities.

Q. Do any third-party regulatory organizations conduct oversight of utility EEI dues?

A. No, there is no regulatory oversight of the allocation of trade association membership dues today. From the 1980s to the early 2000s, NARUC conducted annual audits of trade association financial records through the Committee on Utility Oversight.[100] The audits persuaded NARUC regulators to direct utilities to collect a smaller portion of their EEI dues from ratepayers.[101] The Committee on Utility Oversight, which audited expenditure data, disbanded in the year 2000. Recently, utilities have been seeking lower than usual amounts from shareholders, and correspondingly higher shares from customers—though there is no evidence of a major shift in program efforts at EEI. For example, Georgia Power proposed 29% of EEI dues as below-the-line expenses in a 2016 filing,[102] NV Energy proposed 16% in a 2015 filing,[103] and Oklahoma Gas & Electric proposed 0% in a 2016 filing.[104] Without transparency of spending data, it is difficult to fully understand how EEI spends ratepayer funds. The Commission is the best institution to re-address this issue in the absence of a coordinated multi-state audit like the audit NARUC conducted.

Q. Have other public utility commissions addressed this issue?

A. While I have not conducted a comprehensive survey of all states, commissions in California and Missouri have addressed the issue in recent rate cases. In 2013, the California Public Utilities Commission ("CPUC") decided to decrease the recoverable portion of EEI dues by changing the below-the-line amount of dues from the 25% proposed

[100] *See* NARUC Bd. of Directors, Resolution Regarding Discontinuation of the Committee on Utility Oversight (adopted Mar. 8, 2000), http://pubs.naruc.org/pub/5398B543-2354-D714-51D3-90ACAB1DA952.
[101] *See* EPI, *Paying for Utility Politics*, at 6.
[102] *See id.* at 20.
[103] *See id.* at 24.
[104] *See id.* at 20–21 & tbl.1; Responsive Testimony of Sharhonda Dodoo at 5:17–6:2 & tbl.1, *In re Okla. Gas & Elec. Co.*, No. PUD 201500273 (Corp. Comm'n Okla. Mar. 21, 2016), https://www.documentcloud.org/documents/3111578-Sharhonda-Dodoo-PUD-Testimony-OGE-Dues.html#document/p6/a318911.

by PG&E to 43.3%.[105] The Missouri Public Service Commission ("MO-PSC") has similarly disallowed EEI dues when the utility failed to "develop some method of allocating expenses between its shareholders and the ratepayers once the benefits and activities leading thereto have been adequately quantified."[106]

Q. What do you propose to ensure that ratepayers are not required to fund activities from which they receive no benefit or by which they risk being harmed?

A. The Company must provide sufficiently detailed information regarding the membership dues cost allocation as an incident to its burden of producing sufficient evidence that its requested rates are just and reasonable. This evidence must demonstrate that above-the-line dues to EEI: (1) directly benefit ratepayers and (2) do not work contrary to ratepayer interests. In the absence of a third-party audit in the record, it is not reasonable to rely merely upon the assertions by EEI. The data submitted by the Company therefore is inadequate to carry the Company's burden of demonstrating that its rates are just and reasonable or to confirm that ratepayers are not being asked to pay for lobbying or political advocacy activities carried out by the EEI.

Q. What do you recommend that the Commission do in the face of this lack of evidence?

A. Because the Company has not provided sufficient and competent evidence to support a finding that the dues it is asking ratepayers to pay are a just and reasonable expense, I

[105] *Application of Pac. Gas & Elec. Co. for Auth., Among Other Things, to Increase Rates & Charges for Elec. & Gas Serv. Effective on Jan. 1, 2014 (U39m). & Related Matter.*, 12-11-009, 2014 WL 4248558, at *142 (Aug. 14, 2014); *see also Application of S. California Edison Co. (U338e) for Auth. to, Among Other Things, Increase Its Authorized Revenues for Elec. Serv. in 2015, & to Reflect That Increase in Rates.*, 13-11-003, 2015 WL 7351928, at *200 (Nov. 5, 2015) (reducing recoverable EEI dues from $1.9M to $1M because "SCE has not shown that it has removed all political or lobbying costs from its forecast.")

[106] *In re* Kansas City Power & Light Co., 48 P.U.R.4th 598 (July 14, 1982)

recommend that the total amount of requested revenue requirement related to membership dues in EEI be disallowed.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. Based on your testimony and review of the Company's proposal to increase fixed customer charges for residential and small commercial customers, what conclusions do you reach?

A. The Company's proposal to increase fixed customer charges for residential and commercial secondary customers is based on a flawed regulatory foundation. The major flaws are two: First, the Company provides no reasonable or logical support for its assertion that demand-related costs allocated to small customers should be recovered through a demand charge. Second, the Company provides no reasonable or logical support for its assertion that in the absence of a capability to assess a small customer demand charge, it should be allowed to increase the Rate D1 and D3 fixed customer charges in order to recover demand-related capital and operating costs.

Q. Based on your conclusion, what action do you recommend that the Commission take regarding the Company proposal to increase fixed customer charges for residential and small commercial customers?

A. I recommend that the Commission deny the Company proposal to deny the Company's proposal to increase the fixed customer charges for customers taking service under Rates D1 and D3. Further, the Commission should direct the Company to calculate the costs classified as customer costs including only the costs of connecting customers to the grid and reserve any fixed customer charge solely for recovery of those customer costs.[107]

[107] Because it takes the position that all customer- and demand-related costs should be recovered through the fixed customer charge, the Company did not classify costs as either customer or demand. As a result, the Company has not

Q. Based on your testimony and review of the Company's proposed Rate Rider 18 for distributed generation customers, what conclusions do you reach?

A. The Company's proposal for a new Rate Rider 18 is unjust, unreasonable, unduly discriminatory, and inconsistent with Michigan law and the Commission's regulation and directives.

Q. Based on your conclusions regarding the Company's proposed Rate Rider 18 for distributed generation customers, what action do you recommend that the Commission take?

A. The Commission should deny the Company's proposed Rider 18 in its entirety. The Commission should further direct the Company: (1) to perform an objective and comprehensive assessment of the costs and benefits of serving residential and small commercial DG customers, and to use the results of that assessment in developing a new proposal for inflow charges for DG customer consumption; (2) eliminate its proposal for a SAC charge as not cost-based for services specific to DG customers ; and (3) implement an outflow credit for excess DG production that puts DG customers on an even economic footing with current net metering rates until and unless the Company demonstrates, with competent and objective evidence, that a different outflow credit would be just and reasonable and non-discriminatory.

Q. Based on your testimony and review of the Company's proposal to charge customers for EEI trade association dues, what do you conclude?

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provided a record upon which to base any change in the fixed customer charges for residential and small commercial customers.

A. The Company has failed to produce evidence and prove that the amount of EEI dues it seeks to recover from customers is just and reasonable. The evidence provided based on the unverified assertion of EEI is inadequate to support recovery of the EEI dues expense.

Q. What action do you recommend that the Commission take regarding the Company's proposal for rate recovery of EEI dues?

A. I recommend that the Company disallow the recovery of the entire amount of EEI dues and reduce the Company's revenue requirement accordingly.

Q. Does this conclude your testimony?

A. Yes.

Karl R. Rábago

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Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a research and development manager, utility executive, business builder, sustainability leader, senior government official, consultant, and advocate. Highly proficient in advising, managing, and interacting with government agencies and committees, the media, citizen groups, and business associations. Successful track record of working with U.S. Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. National and international contacts through experience with Pace Energy and Climate Center, Austin Energy, AES Corporation, US Department of Energy, Texas Public Utility Commission, Jicarilla Apache Tribal Utility Authority, Cargill Dow LLC (now NatureWorks, LLC), Rocky Mountain Institute, CH2M HILL, Houston Advanced Research Center, Environmental Defense Fund, and others. Skilled attorney, negotiator, and advisor with more than twenty-five years of experience working with diverse stakeholder communities in electricity policy and regulation, emerging energy markets development, clean energy technology development, electric utility restructuring, smart grid development, and the implementation of sustainability principles. Extensive regulatory practice experience. Nationally recognized speaker on energy, environment, and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at Pace University Elisabeth Haub School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Post-doctorate degrees in environmental and military law. Military veteran.

Employment

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing expert witness and policy formulation advice and services to organizations in the clean and advanced energy sectors. Prepared and submitted testimony in more than 20 states and 60 electricity regulatory proceedings. Recognized national leader in development and implementation of award-winning "Value of Solar" alternative to traditional net metering. Additional information at www.rabagoenergy.com.

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY ELISABETH HAUB SCHOOL OF LAW

Executive Director: May 2014—Present.

Leader of a team of professional and technical experts and law students in energy and climate law, policy, and regulation. Secure funding for and manage execution of research, market development support, and advisory services for a wide range of funders, clients, and stakeholders with the overall goal of advancing clean energy deployment, climate responsibility, and market efficiency. Provide learning and development opportunities for law students. Additional activities:

- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program for green power and green pricing products and programs. Past chair of the Green-e Governance Board.
- Director, Interstate Renewable Energy Council (IREC) (2012-present). IREC focuses on issues impacting expanded renewable energy use such as rules that support renewable energy

and distributed resources in a restructured market, connecting small-scale renewables to the utility grid, developing quality credentials that indicate a level of knowledge and skills competency for renewable energy professionals.

- Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-2017). The NESEMC was a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC worked to harmonize solar market policy and advance supportive policy and regulatory practices in the northeast United States.
- Director, Alliance for Clean Energy – New York (2018-present).

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Government and regulatory affairs manager for AES Wind Generation, one of the largest wind companies in the country. Manage a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets. Active in national policy and the wind industry through work with the American Wind Energy Association as a participant on the organization's leadership council. Also served as Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Authored and implemented a standard of practice based on ISO 14064 and industry best practices. Commissioned the development of a suite of methodologies and tools for various greenhouse gas credit-producing technologies. Also served as Director, Global Regulatory Affairs, providing regulatory support and group management to AES's international electric utility operations on five continents.

JICARILLA APACHE NATION UTILITY AUTHORITY

Director: 1998—2008. Located in New Mexico, the JANUA was an independent utility developing profitable and autonomous utility services that provide natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan with support from U.S. Department of Energy.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications, an industry-driven testing and evaluation center for near-commercial fuel cell generators; the Gulf Coast Combined Heat and Power Application Center, a state and federally funded initiative; and the High Performance Green Buildings Practice, a consulting and outreach initiative. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector. Developed and launched new and integrated program activities relating to hydrogen energy technologies, combined heat and power, distributed energy resources, renewable energy, energy efficiency, green buildings, and regional clean energy development. Active participant in policy development and regulatory implementation in Texas, the Southwest, and national venues. Frequently engaged with policy, regulatory, and market leaders in the region and internationally. Additional activities:

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, leader and manager of successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative acts as an umbrella structure for a number of biofuels related projects, including emissions evaluation for a stationary biodiesel pilot project, feedstock development, and others.
- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Integrated sustainability principles into all aspects of a ground-breaking biobased polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives. NatureWorks is the first company to offer its customers a family of polymers (polylactide – "PLA") derived entirely from annually renewable resources with the cost and performance necessary to compete with packaging materials and traditional fibers; now marketed under the brand name "Ingeo."

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. In two years, co-led the team and grew annual revenues from approximately $300,000 to more than $2 million in annual grant and consulting income. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Worked to increase market opportunities for clean and distributed

energy resources through consulting, research, and publication activities. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles. Frequent appearance in media at international, national, regional and local levels.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs for a not-for-profit environmental group with a staff of 160 and over 300,000 members. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Initiated and managed nationwide collaborative activities aimed at increasing use of renewable energy and energy efficiency technologies in the electric utility industry, including the Green-e Certification Program, Power Scorecard, and others. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Developed, coordinated, and advised on legislation, policy, and renewable energy technology development within the Department, among other agencies, and with Congress. Managed, coordinated, and developed international agreements for cooperative activities in renewable energy and utility sector policy, regulation, and market development between the Department and counterpart foreign national entities. Established and enhanced partnerships with stakeholder groups, including technology firms, electric utility companies, state and local governments, and associations. Supervised development

and deployment support activities at national laboratories. Developed, advocated and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Laid the groundwork for legislative and regulatory adoption of integrated resource planning, electric utility restructuring, and significantly increased use of renewable energy and energy efficiency resources. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT). Member, Southern States Energy Board Integrated Resource Planning Task Force. Member of the University of Houston Environmental Institute Board of Advisors.

LAW TEACHING

Professor for a Designated Service: Pace University Elisabeth Haub School of Law, 2014-present. Non-tenured member of faculty. Courses taught: Energy Law. Supervise a student intern practice program that engages in a wide range of advocacy, analysis, and research activities in support of the mission of the Pace Energy and Climate Center.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law. Provided *pro bono* legal services in administrative proceedings and filings at the Texas Public Utility Commission.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar. Greatly expanded the environmental law curriculum and laid foundation for the concentration program in law. While carrying a full time teaching load, earned an LL.M. in Environmental Law. Established a program for subsequent environmental law professors to obtain an LL.M. prior to joining the faculty.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate. Prosecuted and defended more than 150 felony-level courts-martial. As prosecutor, served as legal officer for two brigade-sized units (approximately 5,000 soldiers), advising commanders on appropriate judicial, non-judicial, separation, and other actions. Pioneered use of some forms of psychiatric and scientific testimony in administrative and judicial proceedings.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Karl R. Rábago

Selected Publications

"Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators," Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016).

"The Net Metering Riddle," Electricity Policy.com, April 2016.

"The Clean Power Plan," Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

"The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age," co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

"Rethinking the Grid: Encouraging Distributed Generation," Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

"The Value of Solar Tariff: Net Metering 2.0," The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

"A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," co-author, Interstate Renewable Energy Council (October 2013)

"The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff," Solar Industry, Vol. 6, No. 1 (Feb. 2013)

"A Review of Barriers to Biofuels Market Development in the United States," 2 Environmental & Energy Law & Policy Journal 179 (2008)

"A Strategy for Developing Stationary Biodiesel Generation," Cumberland Law Review, Vol. 36, p.461 (2006)

"Evaluating Fuel Cell Performance through Industry Collaboration," co-author, Fuel Cell Magazine (2005)

"Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production," co-author, Polymer Degradation and Stability 80, 403-19 (2003)

"An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options," contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

"Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size," co-author, Rocky Mountain Institute (2002)

"Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado," with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

"Study of Electric Utility Restructuring in Alaska," with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

"New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers," EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

"Building a Better Future: Why Public Support for Renewable Energy Makes Sense," Spectrum: The Journal of State Government (Spring 1998)

"The Green-e Program: An Opportunity for Customers," with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

“Being Virtual: Beyond Restructuring and How We Get There,” Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

“Information Technology,” Public Utilities Fortnightly (March 15, 1996)

“Better Decisions with Better Information: The Promise of GIS,” with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

“The Regulatory Environment for Utility Energy Efficiency Programs,” Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

“An Alternative Framework for Low-Income Electric Ratepayer Services,” with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

“What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act,” Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

“Least Cost Electricity for Texas,” State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

“Environmental Costs of Electricity,” Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Virginia SCC Case # PUE-2012-00064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Georgia PSC Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 1203	Louisiana Public Service Commission Re-examination of Net Metering Rules	Louisiana PSC Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Georgia PSC Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	District of Columbia PSC Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	Virginia SCC Case # PUE-2013-00088	Environmental Respondents
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Arizona Corporation Commission Docket # E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jul. 10, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal Setting – FPL, Duke, TECO, Gulf	Florida PSC Docket # 130199-EI, 130200-EI, 130201-EI, 130202-EI	Southern Alliance for Clean Energy
Sep. 19, 2014	Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates	Missouri PSC File No. ET-2014-0350, Tariff # YE-2014-0494	Missouri Solar Energy Industries Association
Aug. 6, 2014	Appalachian Power Company 2014 Biennial Rate Review	Virginia SCC Case # PUE-2014-00026	Southern Environmental Law Center (Environmental Respondents)

Aug. 13, 2014	Wisconsin Public Service Corp. 2014 Rate Application	Wisconsin PSC Docket # 6690-UR-123	RENEW Wisconsin and Environmental Law & Policy Center
Aug. 28, 2014	WE Energies 2014 Rate Application	Wisconsin PSC Docket # 05-UR-107	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 18, 2014	Madison Gas & Electric Company 2014 Rate Application	Wisconsin PSC Docket # 3720-UR-120	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 29, 2014	SOLAR, LLC v. Missouri Public Service Commission	Missouri District Court Case # 14AC-CC00316	SOLAR, LLC
Jan. 28, 2016 (date of CPUC order)	Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, etc.	California PUC Rulemaking 14-07-002	The Utility Reform Network (TURN)
Mar. 20, 2015	Orange and Rockland Utilities 2015 Rate Application	New York PSC Case # 14-E-0493	Pace Energy and Climate Center
May 22, 2015	DTE Electric Company Rate Application	Michigan PSC Case # U-17767	Michigan Environmental Council, NRDC, Sierra Club, and ELPC
Jul. 20, 2015	Hawaiian Electric Company and NextEra Application for Change of Control	Hawai'i PUC Docket # 2015-0022	Hawai'i Department of Business, Economic Development, and Tourism
Sep. 2, 2015	Wisc. PSCo Rate Application	Wisconsin PSC Case # 6690-UR-124	ELPC
Sep. 15, 2015	Dominion Virginia Electric Power 2015 IRP	VA SCC Case # PUE-2015-00035	Environmental Respondents
Sep. 16, 2015	NYSEG & RGE Rate Cases	New York PSC Cases 15-E-0283, -0285	Pace Energy and Climate Center
Oct. 14, 2015	Florida Power & Light Application for CCPN for Lake Okeechobee Plant	Florida PSC Case 150196-EI	Environmental Confederation of Southwest Florida
Oct. 27, 2015	Appalachian Power Company 2015 IRP	VA SCC Case # PUE-2015-00036	Environmental Respondents
Nov. 23, 2015	Narragansett Electric Power/National Grid Rate Design Application	Rhode Island PUC Docket No. 4568	Wind Energy Development, LLC
Dec. 8, 2015	State of West Virginia, et al., v. U.S. EPA, et al.	U.S. Court of Appeals for the District of Columbia Circuit Case No. 15-1363 and Consolidated Cases	Declaration in Support of Environmental and Public Health Intervenors in Support of Movant Respondent-Intervenors' Responses in Opposition to Motions for Stay

Dec. 28, 2015	Ohio Power/AEP Affiliate PPA Application	PUC of Ohio Case No. 14-1693-EL-RDR	Environmental Law and Policy Center
Jan. 19, 2016	Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company Application for Electric Security Plan (FirstEnergy Affiliate PPA)	PUC of Ohio Case No. 14-1297-EL-SSO	Environmental Law and Policy Center
Jan. 22, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case	Indiana Utility Regulatory Commission Cause No. 44688	Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case – Settlement Testimony	Indiana Utility Regulatory Commission Cause No. 44688	Joint Intervenors - Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Comments on Pilot Rate Proposals by MidAmerican and Alliant	Iowa Utility Board NOI-2014-0001	Environmental Law and Policy Center
May 27, 2016	Consolidated Edison of New York Rate Case	New York PSC Case No. 16-E-0060	Pace Energy and Climate Center
June 21, 2016	Federal Trade Commission: Workshop on Competition and Consumer Protection Issues in Solar Energy	Invited workshop presentation	Pace Energy and Climate Center
Aug. 17, 2016	Dominion Virginia Electric Power 2016 IRP	VA SCC Case # PUE-2016-00049	Environmental Respondents
Sep. 13, 2016	Appalachian Power Company 2016 IRP	VA SCC Case # PUE-2016-00050	Environmental Respondents
Oct. 27, 2016	Consumers Energy PURPA Compliance Filing	Michigan PSC Case No. U-18090	Environmental Law & Policy Center, “Joint Intervenors”
Oct. 28, 2016	Delmarva, PEPCO (PHI) Utility Transformation Filing – Review of Filing & Utilities of the Future Whitepaper	Maryland PSC Case PC 44	Public Interest Advocates
Dec. 1, 2016	DTE Electric Company PURPA Compliance Filing	Michigan PSC Case No. U-18091	Environmental Law & Policy Center, “Joint Intervenors”
Dec. 16, 2016	Rebuttal of Unitil Testimony in Net Energy Metering Docket	New Hampshire Docket No. DE 16-576	New Hampshire Sustainable Energy Association (“NHSEA”)
Jan. 13, 2017	Gulf Power Company Rate Case	Florida Docket No. 160186-EI	Earthjustice, Southern Alliance for Clean Energy, League of Women Voters-Florida

Jan. 13, 2017	Alpena Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18089	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Indiana Michigan Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18092	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Northern States Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18093	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Upper Peninsula Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18094	Environmental Law & Policy Center, "Joint Intervenors"
Mar. 10, 2017	Eversource Energy Grid Modernization Plan	Massachusetts DPU Case No. 15-122/15-123	Cape Light Compact
Apr. 27, 2017	Eversource Rate Case & Grid Modernization Investments	Massachusetts DPU Case No. 17-05	Cape Light Compact
May 2, 2017	AEP Ohio Power Electric Security Plan	PUC of Ohio Case No. 16-1852-EL-SSO	Environmental Law & Policy Center
Jun. 2, 2017	Vectren Energy TDSIC Plan	Indiana URC Cause No. 44910	Citizens Action Coalition & Valley Watch
Jul. 28, 2017	Vectren Energy 2016-2017 Energy Efficiency Plan	Indiana URC Cause No. 44645	Citizens Action Coalition
Jul. 28, 2017	Vectren Energy 2018-2020 Energy Efficiency Plan	Indiana URC Cause No. 44927	Citizens Action Coalition
Aug. 11, 2017	Dominion Virginia Electric Power 2017 IRP	VA SCC Case # PUR-2017-00051	Environmental Respondents
Aug. 18, 2017	Appalachian Power Company 2017 IRP	VA SCC Case # PUR-2017-00045	Environmental Respondents
Aug. 25, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	NY PSC Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center
Sep. 15, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	NY PSC Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center
Oct. 20, 2017	Missouri PSC Working Case to Explore Emerging Issues in Utility Regulation	MO PSC File No. EW-2017-0245	Renew Missouri
Nov. 21, 2017	Central Hudson Gas & Electric Co. Electric and Gas Rates Cases	NY PSC Case # 17-E-0459, -0460	Pace Energy and Climate Center

Jan. 16, 2018	Great Plains Energy, Inc. Merger with Westar Energy, Inc.	Missouri PSC Case # EM-2018-0012	Renew Missouri Advocates
Jan. 19, 2018	U.S. House of Representatives, Energy and Commerce Committee	Hearing on "The PURPA Modernization Act of 2017," H.R. 4476	Rábago Energy LLC
Jan. 29, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Mass. D.P.U. Case No. 17-140	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Feb. 21, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Mass. D.P.U. Case No. 17-140 - Surrebuttal	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Apr. 6, 2018	Narragansett Electric Co., d/b/a National Grid Rate Case Filing	RI PUC Docket No. 4770	New Energy Rhode Island ("NERI")
Apr. 25, 2018	Narragansett Electric Co., d/b/a National Grid Power Sector Transformation Plan	Rhode Island PUC Docket No. 4780	New Energy Rhode Island ("NERI")
Apr. 26, 2018	U.S. EPA Proposed Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Stories: Electric Utility Generating Units, 82 Fed. Reg. 48,035 (Oct. 16, 2017) – "Clean Power Plan"	U.S. EPA Docket No. EPA-HQ-OAR-2016-0592	Karl R. Rábago
May 25, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	NY PSC Case Nos. 18-E-0067, 18-G-0068	Pace Energy and Climate Center
Jun. 15, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	NY PSC Case Nos. 18-E-0067, 18-G-0068 – Rebuttal Testimony	Pace Energy and Climate Center
Aug. 10, 2018	Dominion Virginia Electric Power 2018 IRP	VA SCC Case # PUR-2018-00065	Environmental Respondents
Sep. 20, 2018	Consumers Energy Company Rate Case	Michigan PSC Case No. U-20134	Environmental Law & Policy Center

MPSC Case No.:	U-20162
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-8.18
Respondent:	Legal/T. W. Lacey
Page:	1 of 1

Question: Please explain the Company position that demand related costs should be recovered through fixed or per-customer charges in order to advance economic efficiency. If this is not the Company position, please explain.

Answer: DTE objects to the request for the reason that the request is vague, unclear, and incapable of answer in its current form since the Company is unclear on what is meant by "economic efficiency." Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

The Company believes that costs that do not vary based on energy (i.e. fixed costs) should be recovered through charges that do not vary based on energy, as it best matches cost causation to cost recovery. Also, please see my testimony at pages TWL-18 to 24.

Attachments: *N/A*

MPSC Case No.:	U-20162
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-8.19
Respondent:	Legal/T. W. Lacey
Page:	1 of 1

Question: Please explain whether the Company position is that all demand related costs should be recovered through fixed charges in order to advance economic efficiency. If this is not the Company position, please explain which demand related costs the Company believes should be recovered through fixed or per-customer charges. Please detail the Company's method for distinguishing between demand related costs that it asserts should be recovered through fixed or per-customer charges. Please detail how that method is reflected in the application in this proceeding, including references to specific numbers in exhibits attached to this application.

Answer: DTE objects to the request for the reason that the request is vague, unclear, and incapable of answer in its current form since the Company is unclear on what is meant by "economic efficiency." Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

The Company believes all demand costs should be recovered through fixed charges, as it best matches cost causation to cost recovery.

Please see response to MECNRDCSCDE-8.16. The specific numbers identified for actual or potential recovery through fixed charges are reflected Exhibit No. A-16, Schedules F1.1, F1.2, F1.4 and F1.5. Please see my testimony at pages TWL-6 to 24 for the detailed explanation.

Attachments: *N/A*

MPSC Case No.:	U-20162
Requestor:	MECNRDCSCDE
Question No.:	MECNRDCSCDE-1.18d
Respondent:	T. W.Lacey/ K.O. Farrell
Page:	1 of 1

Question: Please reference Dennis Direct at 21:17-20.

d. Please state whether you contend that there is greater correlation between each individual customer's maximum monthly demand and that customer's individual contribution to class NCP used to allocate demand costs in the cost of service study, than between each customer's individual kWh consumption and that customer's individual contribution to class NCP used to allocate demand costs in the cost of service study.

Answer: The Company does not allocate distribution costs based on individual customer's maximum monthly demands. See response to MECNRDCSCDE-1.23c, which subject to objection states as follows: None of the amounts used in the U-20162 Cost of Service study reflect individual customer's detail, however if I use total voltage class amounts and assuming: (1) I use allocation schedule 300 reflected on page 13 of Exhibit A-17, Schedule G1.2, which reflects annual maximum demands, (2) "customer's contribution to class NCP" means allocation schedule no. 202c per page 7 of Exhibit A-17, Schedule G1.2, and (3) a "customer's kWh imports" means the projected energy sales as reflected on Exhibit A-17, Schedule G1.1. I would answer as follows: I can not determine the level of stastically significant correlation, but I can state for the forecasted values reflected in this case the former shows more variation than the latter for residential and less variation for commercial secondary. (See attached file "U-20162 MECNRDSCDE-1.23" for the calculation.)

MPSC Case No.:	U-20162
Requestor:	MECNRDCSCDE
Question No.:	MECNRDCSCDE-1.23c
Respondent:	T. W. Lacey/Legal
Page:	1 of 1

Question: Please reference Lacey Direct at 18:24-20:19.

c. Do you contend that there is a more significant correlation between an individual customer's contribution to class NCP and that customer's individual monthly maximum demand, than between an individual customer's contribution to class NCP and the customer's kWh imports?

Answer: DTE Electric objects because the request is unclear and unduly vague and incapable of answer in its present form since the Company is unclear regarding the comparison requested using the terms stated in the question. Subject to this objection, and without waiving this objection, the Company would answer as follows:

None of the amounts used in the U-20162 Cost of Service study reflect individual customer's detail, however if I use total voltage class amounts and assuming: (1) I use allocation schedule 300 reflected on page 13 of Exhibit A-17, Schedule G1.2, which reflects annual maximum demands, (2) "customer's contribution to class NCP" means allocation schedule no. 202c per page 7 of Exhibit A-17, Schedule G1.2, and (3) a "customer's kWh imports" means the projected energy sales as reflected on Exhibit A-17, Schedule G1.1. I would answer as follows: I can not determine the level of stastically significant correlation, but I can state for the forecasted values reflected in this case the former shows more variation than the latter. for residential and less variation for commercial secondary. (See attached file "U-20162 MECNRDSCDE-1.23" for the calculation.)

Michigan Public Service Commission

DTE Electric Company

Support for Discovery Response MECNRDCSCDE-1.23c

		Max Demand	%/Ratio	Source
		Sch 300		
1	Res		70.36%	Exh A-17, sch G1.2 Page 17 Line 1 col. (C)
2	Com sec		29.26%	Exh A-17, sch G1.2 Page 17 Line 7 col. (C)
3				
4				
5				
6		Sch 202c		
7		NCP		
8				
9	Res		48.69%	Exh A-17, sch G1.2 Page 7 Line 2 col. (C)
10	Com sec		26.74%	Exh A-17, sch G1.2 Page 7 Line 7 col. (C)
11				
12		Ratio		
13				
14	Res		1.45	Line 1/Line 9
15	Com sec		1.09	Line 2/Line 10
16				
17		Energy Sales		
18	Res	16,335,533	36.56%	Exh A-17, sch G1.1 Lines 2-4 col. (B)
19	Com sec	10,563,282	23.64%	Exh A-17, sch G1.1 Lines 9-11 col. (B)
20				
21	Total	44,685,656		
22				
23		Ratio		
24	Res		1.33	Line 9/Line 18
25	Com sec		1.13	Line 10/Line 19

MPSC Case No.: U-20162
Requestor: MECNRDCSCDE
Question No.: MECNRDCSCDE-2.11
Respondent: T. D. Johnson
Page: 1 of 1

Question: Refer to Tamara Johnson direct testimony concerning low income programs. Produce any and all data in the possession or control of DTE regarding poverty rates in the Company's service territory, and any and all data regarding the numbers of DTE customers the Company would consider to be low income.

Answer: The low income data as of August 2018 is as follows:

Num of BPs	Num of CAs	Num of Contracts	Num of Premise
164,475	175,136	300,791	174,035

Customers identified as low income are at or below 200% of the Federal Poverty Level.

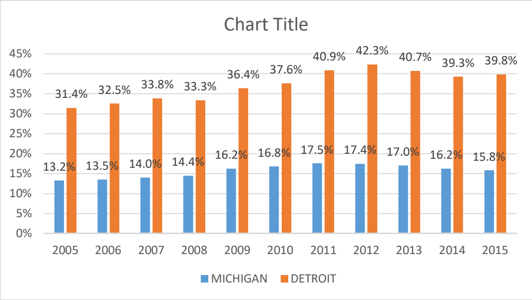
MPSC Case No.: U-18255
Respondent: M. C. Johnson
Requestor: MECNRDCSC-1
Question No.: MECNRDCSCDE-1.19
Page: 1 of 1

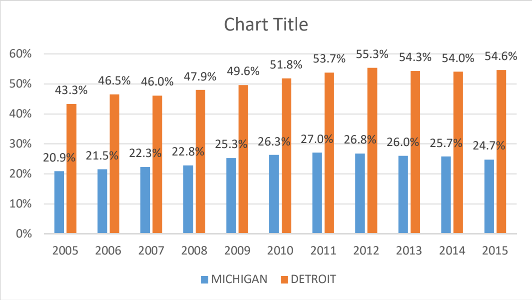
Question: Refer to direct testimony of Mark Johnson, page 22, lines 21-24. Produce any and all data in DTE's possession or control regarding poverty rates (and rates of increase in same) in the Company's service territory.

Answer: Please see the attachment, "U-18255 MECNRDCSCDE-1.19 Demographics".

https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_15_1YR_S1701&prodType=table

MICHIGAN	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Population for whom poverty status is determined	9,830,885	9,852,543	9,832,533	9,769,537	9,735,741	9,656,449	9,656,260	9,663,760	9,669,513	9,686,787	9,698,396
Below poverty level	1,299,688	1,331,833	1,376,658	1,410,276	1,576,704	1,618,257	1,693,294	1,685,178	1,648,436	1,568,844	1,529,645
	13.2%	13.5%	14.0%	14.4%	16.2%	16.8%	17.5%	17.4%	17.0%	16.2%	15.8%
150 percent of poverty level	2,055,201	2,115,954	2,193,987	2,224,040	2,459,508	2,536,075	2,608,572	2,588,971	2,518,135	2,493,432	2,394,986
	20.9%	21.5%	22.3%	22.8%	25.3%	26.3%	27.0%	26.8%	26.0%	25.7%	24.7%
200 percent of poverty level	2,873,439	2,961,488	3,026,225	3,103,459	3,374,521	3,444,954	3,488,897	3,488,070	3,446,237	3,359,370	3,279,049
	29.2%	30.1%	30.8%	31.8%	34.7%	35.7%	36.1%	36.1%	35.6%	34.7%	33.8%
DETROIT	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Population for whom poverty status is determined	832,680	817,638	796,076	766,714	897,869	702,010	695,930	691,284	678,700	669,071	665,640
Below poverty level	261,497	265,600	269,011	255,559	326,764	263,864	284,421	292,391	276,186	262,767	265,097
	31.4%	32.5%	33.8%	33.3%	36.4%	37.6%	40.9%	42.3%	40.7%	39.3%	39.8%
150 percent of poverty level	360,486	379,988	366,277	367,258	445,357	363,720	373,936	382,506	368,458	361,175	363,142
	43.3%	46.5%	46.0%	47.9%	49.6%	51.8%	53.7%	55.3%	54.3%	54.0%	54.6%
200 percent of poverty level	452,787	462,911	448,722	452,914	555,363	444,839	452,118	451,207	434,515	435,180	437,067
	54.4%	56.6%	56.4%	59.1%	61.9%	63.4%	65.0%	65.3%	64.0%	65.0%	65.7%





https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_15_1YR_S1702&prodType=table

MICHIGAN	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
All families	2,594,228	2,579,201	2,560,681	2,525,388	2,523,758	2,508,780	2,472,884	2,482,612	2,484,558	2,485,159	2,479,724
Percent below poverty level	9.9%	9.6%	10.1%	10.5%	11.6%	12.1%	12.5%	12.6%	12.3%	11.4%	11.1%
Below poverty level	256,829	247,603	258,629	265,166	292,756	303,562	309,111	312,809	305,601	283,308	275,249
DETROIT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
All families	189,728	180,216	165,521	158,012	188,297	148,316	145,224	145,294	144,476	141,250	141,284
Percent below poverty level	27.0%	27.0%	28.2%	30.3%	31.3%	32.3%	35.5%	37.7%	35.4%	33.8%	35.5%
Below poverty level	51,227	48,658	46,677	47,878	58,937	47,906	51,555	54,776	51,145	47,743	50,156
MICHIGAN	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
50 percent of poverty level											111,906
125 percent of poverty level											360,566
150 percent of poverty level											451,807
185 percent of poverty level											594,331
200 percent of poverty level											652,713
DETROIT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
50 percent of poverty level											22,337
125 percent of poverty level											61,017
150 percent of poverty level											69,790
185 percent of poverty level											81,780
200 percent of poverty level											85,841

https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_15_1YR_DP03&prodType=table

MPSC Case No.:	U-20162
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-8.20
Respondent:	T. W. Lacey
Page:	1 of 1

Question: Please provide citations, including references to specific language, for all treatises, scholarly articles, texts, commission decisions, statutes, or any other references relied upon by the Company that assert or support the proposition that economic efficiency, fairness, and/or reasonableness are advanced when fixed costs of any type are recovered through fixed charges of any type.

Answer: I have no citation that explicitly states "economic efficiency, fairness, and/or reasonableness are advanced when fixed costs of any type are recovered through fixed charges of any type." However, the Blank and Gegax article in the April 2016 issue of *The Electricity Journal,* Volume 29, Issue 3, pages 42-47 entitled *An Enhanced Two-Part Tariff Methodology When Demand Charges Are Not Used,"* supports the argument that demand costs should be collected through a customer charge when a demand charge is not an option.

Attachments: *N/A*

MPSC Case No.:	U-20162
Requestor:	ELPC
Question No.:	ELPCDE-2.84
Respondent:	P. W. Dennis
Page:	1 of 1

Question: Provide all bill impact analyses that have been conducted on the effect of the proposed DG tariff changes (including the SAC) compared to customers without DG and customers currently taking service under Rider 16. Data should be provided in its native format with formulas intact. If any workpaper has an external link to another workpaper, provide the supplemental workpaper. If any workpaper has hardcoded figures derived from another workpaper, provide the supplemental workpapers.

Answer: The Company has not completed a bill impact analyses comparing the effect of the proposed rates and DG tariff changes (including the SAC) compared to customers without DG, and customers currently taking service under Rider 16. However, the Company did complete a bill impact analysis on earlier iterations of a similar concept. Note, this bill impact analysis does not reflect the rates proposed in this case. See also the response to ELPCDE-2.61.

Attachments: U-20162 ELPCDE-2.84 analysis.xls

Customer 1 Inputs

Month	Gen	In	Out	In + Gen - Out
1	44.62	401	22	424
2	140.08	474	92	522
3	405.77	569	249	725
4	617.28	536	476	677
5	672.72	406	490	589
6	661.45	381	480	563
7	657.06	360	495	522
8	616.61	408	454	571
9	489.14	440	341	588
10	321.40	605	201	726
11	201.83	809	92	919
12	172.06	869	63	978
	5000	6258	3454	7803

D1 Rate

First Block	$0.08035
Second Block	$0.09599
PSCR	-$0.000870
Service Charge	$7.50
Distribution Rate (I	$0.05529
Nuclear	0.000728
EO	$0.003396
LIEAF	$0.93
Total Fix	$8.43
Total Dist Surchagr	$0.00412

Outflow Credit I ($0.035)

Annual Summary	Total Bill	Bank Value Remaining
No gen	$1,212	N/A
Cat 1 NM	$500	$0
In/Out - LMP Outflow	$862	$0

D1 - no net meter

Month	Days	Total Use	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Total Bill
1	31	424	424	$34.05	0	0	-0.37	$33.68	$8.43	$23.43	$1.75	$33.61	$67.29
2	28	522	476	$38.25	46	4.44	-0.45	$42.24	$8.43	$28.87	$2.15	$39.45	$81.69
3	31	725	527	$42.34	198	19	-0.63	$60.71	$8.43	$40.08	$2.99	$51.50	$112.21
4	30	677	510	$40.98	167	16.06	-0.59	$56.45	$8.43	$37.45	$2.79	$48.67	$105.12
5	31	589	527	$42.34	62	5.93	-0.51	$47.76	$8.43	$32.55	$2.43	$43.41	$91.17
6	30	563	510	$40.98	53	5.04	-0.49	$45.53	$8.43	$31.10	$2.32	$41.85	$87.38
7	31	522	522	$41.91	0	0	-0.45	$41.46	$8.43	$28.84	$2.15	$39.42	$80.88
8	31	571	527	$42.34	44	4.22	-0.5	$46.06	$8.43	$31.57	$2.35	$42.35	$88.41
9	30	588	510	$40.98	78	7.53	-0.51	$48.00	$8.43	$32.54	$2.43	$43.40	$91.40
10	31	726	527	$42.34	199	19.09	-0.63	$60.80	$8.43	$40.14	$2.99	$51.56	$112.36
11	30	919	510	$40.98	409	39.28	-0.8	$79.46	$8.43	$50.82	$3.79	$63.04	$142.50
12	31	978	527	$42.34	451	43.27	-0.85	$84.76	$8.43	$54.06	$4.03	$66.52	$151.28
ANNUAL								$646.91				$564.78	$1,211.69

D1 - Category 1 Net Metering

Month	Days	Net Inflow	First Block kWh	First Block	Excess Gen Cred	Second Block kWh	Second Block Bill	Excess Gen Cred	PSCR Bill	Excess Gen Credit	PS Total	Fixed Charges	Distribution Bill	Excess Gen Cred	Dist Surch Bill	Dist subtotal	Total Bill	Bank Start	Bank Change	Bank End		
1	31	379	379	$30.46		0	0		-0.33		$30.13	$8.43	$20.96		$1.56	$30.95	$61.08	0	0	0		
2	28	382	382	$30.71		0	0		-0.33		$30.38	$8.43	$21.13		$1.58	$31.14	$61.52	0	0	0		
3	31	319	319	$25.64		0	0		-0.28		$25.36	$8.43	$17.65		$1.32	$27.40	$52.76	0	0	0		
4	30	60	60	$4.83		0	0		-0.05		$4.78	$8.43	$3.32		$0.25	$12.00	$16.78	0	0	0		
5	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	0	84	84		
6	30	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	84	99	183		
7	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	183	136	318		
8	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	318	46	364		
9	30	99	99	$7.98	-$7.98	0	0		-0.09	0.09	$0.00	$8.43	$5.49	-$5.49	$0.41	$8.84	$8.84	364	-99	265		
10	31	405	405	$32.50	-$21.27	0	0		-0.35	$0.23	$11.11	$8.43	$22.37	-$14.63	$1.67	$17.84	$28.95	265	-265	0		
11	30	717	510	$40.98		207	19.91		-0.62		$60.27	$8.43	$39.66		$2.96	$51.05	$111.32	0	0	0		
12	31	806	527	$42.34		279	26.75		-0.7		$68.39	$8.43	$44.55		$3.32	$56.30	$124.69	0	0	0		
ANNUAL											$230.42					$269.24	$499.66			0	$0.13	$0.00

D1 - Inflow/outflow method at LMP Outflow Credit

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Outflow kWh	LMP Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	401	401	$32.25	0	0	-0.35	$31.90	$8.43	$22.19	$1.66	$32.28	22	-$0.78	$63.40	no excess	0	0	0
2	28	474	474	$38.07	0	0	-0.41	$37.66	$8.43	$26.19	$1.95	$36.57	92	-$3.21	$71.02	no excess	0	0	0
3	31	569	527	$42.34	42	4	-0.49	$45.85	$8.43	$31.44	$2.35	$42.22	249	-$8.73	$79.34	no excess	0	0	0
4	30	536	510	$40.98	26	2.47	-0.47	$42.98	$8.43	$29.62	$2.21	$40.26	476	-$16.65	$66.59	no excess	0	0	0
5	31	406	406	$32.60	0	0	-0.35	$32.25	$8.43	$22.44	$1.67	$32.54	490	-$17.14	$47.65	no excess	0	0	0
6	30	381	381	$30.63	0	0	-0.33	$30.30	$8.43	$21.08	$1.57	$31.08	480	-$16.80	$44.58	no excess	0	0	0
7	31	360	360	$28.89	0	0	-0.31	$28.58	$8.43	$19.88	$1.48	$29.79	495	-$17.33	$41.04	no excess	0	0	0
8	31	408	408	$32.77	0	0	-0.35	$32.42	$8.43	$22.55	$1.68	$32.66	454	-$15.87	$49.21	no excess	0	0	0
9	30	440	440	$35.39	0	0	-0.38	$35.01	$8.43	$24.35	$1.82	$34.60	341	-$11.94	$57.67	no excess	0	0	0
10	31	605	527	$42.34	78	7.53	-0.53	$49.34	$8.43	$33.48	$2.50	$44.41	201	-$7.03	$86.72	no excess	0	0	0
11	30	809	510	$40.98	299	28.72	-0.7	$69.00	$8.43	$44.74	$3.34	$56.51	92	-$3.21	$122.30	no excess	0	0	0
12	31	869	527	$42.34	342	32.8	-0.76	$74.38	$8.43	$48.03	$3.58	$60.04	63	-$2.21	$132.21	no excess	0	0	0
ANNUAL								$509.67				$472.96			$861.73				

D1 - Inflow/outflow method, grid charge, and LMP outflow

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Grid Charge	Outflow kWh	Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	401	401	$32.25	0	0	-0.35	$31.90	$8.43	$22.19	$1.66	$32.28	$10.25	22	-$0.78	$73.65	no excess	0	0	0
2	28	474	474	$38.07	0	0	-0.41	$37.66	$8.43	$26.19	$1.95	$36.57	$10.25	92	-$3.21	$81.27	no excess	0	0	0
3	31	569	527	$42.34	42	4	-0.49	$45.85	$8.43	$31.44	$2.35	$42.22	$10.25	249	-$8.73	$89.59	no excess	0	0	0
4	30	536	510	$40.98	26	2.47	-0.47	$42.98	$8.43	$29.62	$2.21	$40.26	$10.25	476	-$16.65	$76.84	no excess	0	0	0
5	31	406	406	$32.60	0	0	-0.35	$32.25	$8.43	$22.44	$1.67	$32.54	$10.25	490	-$17.14	$57.90	no excess	0	0	0
6	30	381	381	$30.63	0	0	-0.33	$30.30	$8.43	$21.08	$1.57	$31.08	$10.25	480	-$16.80	$54.82	no excess	0	0	0
7	31	360	360	$28.89	0	0	-0.31	$28.58	$8.43	$19.88	$1.48	$29.79	$10.25	495	-$17.33	$51.29	no excess	0	0	0
8	31	408	408	$32.77	0	0	-0.35	$32.42	$8.43	$22.55	$1.68	$32.66	$10.25	454	-$15.87	$59.46	no excess	0	0	0
9	30	440	440	$35.39	0	0	-0.38	$35.01	$8.43	$24.35	$1.82	$34.60	$10.25	341	-$11.94	$67.92	no excess	0	0	0
10	31	605	527	$42.34	78	7.53	-0.53	$49.34	$8.43	$33.48	$2.50	$44.41	$10.25	201	-$7.03	$96.96	no excess	0	0	0
11	30	809	510	$40.98	299	28.72	-0.7	$69.00	$8.43	$44.74	$3.34	$56.51	$10.25	92	-$3.21	$132.55	no excess	0	0	0
12	31	869	527	$42.34	342	32.8	-0.76	$74.38	$8.43	$48.03	$3.58	$60.04	$10.25	63	-$2.21	$142.46	no excess	0	0	0
								$509.67				$472.96	$122.98		-$120.90	$984.71				

Customer 1 Inputs

Month	Gen	In	Out	In + Gen - Out
1	13.93	304.826	2.103	317
2	67.11	377.045	12.254	432
3	103.8	397.648	31.733	470
4	149.6	305.947	65.245	390
5	139.1	382.455	47.315	474
6	131.4	448.05	30.525	549
7	141.8	457.178	31.911	567
8	131.5	448.952	32.982	547
9	112.9	334.073	44.935	402
10	72.09	290.486	27.451	335
11	42.78	359.68	10.206	392
12	34.41	410.186	4.18	440
				5316

D1 Rate

First Block	$0.08035	Outflow Credit	($0.035)
Second Block	$0.09599		
PSCR	-$0.000870		
Service Charge	$7.50		
Distribution Rate	$0.05529		
Nuclear	0.000728		
EO	$0.003396		
LIEAF	$0.93		
Total Fix	$8.43		
Total Dist Surcha	$0.00412		

Annual Summary	Total Bill	Bank Value Remaining
No gen	$841	N/A
Cat 1 NM	$681	$0.00
In/Out - LMP Outflow	$717	0

D1 - no net meter

Month	Days	Total Use	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Total Bill
1	31	317	317	$25.44	0	0	-0.28	$25.16	$8.43	$17.51	$1.31	$27.25	$52.41
2	28	432	432	$34.70	0	0	-0.38	$34.32	$8.43	$23.88	$1.78	$34.09	$68.41
3	31	470	470	$37.74	0	0	-0.41	$37.33	$8.43	$25.97	$1.94	$36.34	$73.67
4	30	390	390	$31.36	0	0	-0.34	$31.02	$8.43	$21.58	$1.61	$31.62	$62.64
5	31	474	474	$38.10	0	0	-0.41	$37.69	$8.43	$26.22	$1.96	$36.61	$74.30
6	30	549	510	$40.98	39	3.74	-0.48	$44.24	$8.43	$30.35	$2.26	$41.04	$85.28
7	31	567	527	$42.34	40	3.85	-0.49	$45.70	$8.43	$31.35	$2.34	$42.12	$87.82
8	31	547	527	$42.34	20	1.96	-0.48	$43.82	$8.43	$30.27	$2.26	$40.96	$84.78
9	30	402	402	$32.31	0	0	-0.35	$31.96	$8.43	$22.23	$1.66	$32.32	$64.28
10	31	335	335	$26.93	0	0	-0.29	$26.64	$8.43	$18.53	$1.38	$28.34	$54.98
11	30	392	392	$31.52	0	0	-0.34	$31.18	$8.43	$21.69	$1.62	$31.74	$62.92
12	31	440	440	$35.39	0	0	-0.38	$35.01	$8.43	$24.35	$1.82	$34.60	$69.61
ANNUAL								$424.07				$417.03	$841.10

D1 - Category 1 Net Metering

Month	Days	Net Inflow	First Block kWh	First Block	Excess Gen Cred	Second Block kWh	Second Block Bill	Excess Gen Cred	PSCR Bill	Excess Gen Credit	PS Total	Fixed Charges	Distribution Bill	Excess Gen Cred	Dist Surch Bill	Dist subtotal	Total Bill	Bank Start	Bank Change	Bank End		
1	31	303	303	$24.32		0	0		-0.26		$24.06	$8.43	$16.74		$1.25	$26.42	$50.48	0	0	0		
2	28	365	365	$29.31		0	0		-0.32		$28.99	$8.43	$20.17		$1.50	$30.10	$59.09	0	0	0		
3	31	366	366	$29.40		0	0		-0.32		$29.08	$8.43	$20.23		$1.51	$30.17	$59.25	0	0	0		
4	30	241	241	$19.34		0	0		-0.21		$19.13	$8.43	$13.31		$0.99	$22.73	$41.86	0	0	0		
5	31	335	335	$26.93		0	0		-0.29		$26.64	$8.43	$18.53		$1.38	$28.34	$54.98	0	0	0		
6	30	418	418	$33.55		0	0		-0.36		$33.19	$8.43	$23.08		$1.72	$33.23	$66.42	0	0	0		
7	31	425	425	$34.17		0	0		-0.37		$33.80	$8.43	$23.51		$1.75	$33.69	$67.49	0	0	0		
8	31	416	416	$33.42		0	0		-0.36		$33.06	$8.43	$23.00		$1.72	$33.15	$66.21	0	0	0		
9	30	289	289	$23.23		0	0		-0.25		$22.98	$8.43	$15.99		$1.19	$25.61	$48.59	0	0	0		
10	31	263	263	$21.13		0	0		-0.23		$20.90	$8.43	$14.54		$1.08	$24.05	$44.95	0	0	0		
11	30	349	349	$28.08		0	0		-0.3		$27.78	$8.43	$19.32		$1.44	$29.19	$56.97	0	0	0		
12	31	406	406	$32.62		0	0		-0.35		$32.27	$8.43	$22.45		$1.67	$32.55	$64.82	0	0	0		
ANNUAL											$331.88					$349.23	$681.11			0	$0.13	$0.00

D1 - Inflow/outflow method at LMP Outflow Credit

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Outflow kWh	LMP Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	305	305	$24.49	0	0	-0.27	$24.22	$8.43	$16.85	$1.26	$26.54	2	-$0.07	$50.69	no excess	0	0	0
2	28	377	377	$30.30	0	0	-0.33	$29.97	$8.43	$20.85	$1.55	$30.83	12	-$0.43	$60.37	no excess	0	0	0
3	31	398	398	$31.95	0	0	-0.35	$31.60	$8.43	$21.99	$1.64	$32.06	32	-$1.11	$62.55	no excess	0	0	0
4	30	306	306	$24.58	0	0	-0.27	$24.31	$8.43	$16.92	$1.26	$26.61	65	-$2.28	$48.64	no excess	0	0	0
5	31	382	382	$30.73	0	0	-0.33	$30.40	$8.43	$21.15	$1.58	$31.16	47	-$1.66	$59.90	no excess	0	0	0
6	30	448	448	$36.00	0	0	-0.39	$35.61	$8.43	$24.77	$1.85	$35.05	31	-$1.07	$69.59	no excess	0	0	0
7	31	457	457	$36.73	0	0	-0.4	$36.33	$8.43	$25.28	$1.89	$35.60	32	-$1.12	$70.81	no excess	0	0	0
8	31	449	449	$36.07	0	0	-0.39	$35.68	$8.43	$24.82	$1.85	$35.10	33	-$1.15	$69.63	no excess	0	0	0
9	30	334	334	$26.84	0	0	-0.29	$26.55	$8.43	$18.47	$1.38	$28.28	45	-$1.57	$53.26	no excess	0	0	0
10	31	290	290	$23.34	0	0	-0.25	$23.09	$8.43	$16.06	$1.20	$25.69	27	-$0.96	$47.82	no excess	0	0	0
11	30	360	360	$28.90	0	0	-0.31	$28.59	$8.43	$19.89	$1.48	$29.80	10	-$0.36	$58.03	no excess	0	0	0
12	31	410	410	$32.96	0	0	-0.36	$32.60	$8.43	$22.68	$1.69	$32.80	4	-$0.15	$65.25	no excess	0	0	0
ANNUAL								$358.95				$369.52			$716.54				

D1 - Inflow/outflow method, grid charge, and LMP outflow

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Grid Charge	Outflow kWh	Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	305	305	$24.49	0	0	-0.27	$24.22	$8.43	$16.85	$1.26	$26.54	$2.44	2	-$0.07	$53.13	no excess	0	0	0
2	28	377	377	$30.30	0	0	-0.33	$29.97	$8.43	$20.85	$1.55	$30.83	$2.44	12	-$0.43	$62.81	no excess	0	0	0
3	31	398	398	$31.95	0	0	-0.35	$31.60	$8.43	$21.99	$1.64	$32.06	$2.44	32	-$1.11	$64.99	no excess	0	0	0
4	30	306	306	$24.58	0	0	-0.27	$24.31	$8.43	$16.92	$1.26	$26.61	$2.44	65	-$2.28	$51.08	no excess	0	0	0
5	31	382	382	$30.73	0	0	-0.33	$30.40	$8.43	$21.15	$1.58	$31.16	$2.44	47	-$1.66	$62.34	no excess	0	0	0
6	30	448	448	$36.00	0	0	-0.39	$35.61	$8.43	$24.77	$1.85	$35.05	$2.44	31	-$1.07	$72.03	no excess	0	0	0
7	31	457	457	$36.73	0	0	-0.4	$36.33	$8.43	$25.28	$1.89	$35.60	$2.44	32	-$1.12	$73.25	no excess	0	0	0
8	31	449	449	$36.07	0	0	-0.39	$35.68	$8.43	$24.82	$1.85	$35.10	$2.44	33	-$1.15	$72.07	no excess	0	0	0
9	30	334	334	$26.84	0	0	-0.29	$26.55	$8.43	$18.47	$1.38	$28.28	$2.44	45	-$1.57	$55.70	no excess	0	0	0
10	31	290	290	$23.34	0	0	-0.25	$23.09	$8.43	$16.06	$1.20	$25.69	$2.44	27	-$0.96	$50.26	no excess	0	0	0
11	30	360	360	$28.90	0	0	-0.31	$28.59	$8.43	$19.89	$1.48	$29.80	$2.44	10	-$0.36	$60.47	no excess	0	0	0
12	31	410	410	$32.96	0	0	-0.36	$32.60	$8.43	$22.68	$1.69	$32.80	$2.44	4	-$0.15	$67.69	no excess	0	0	0
								$358.95				$369.52	$29.28		-$11.93	$745.82				

Customer 1 Inputs

Month	Gen	In	Out	In + Gen - Out
1	202.3	416.823	101.517	518
2	494.1	447.381	297.102	644
3	647.9	484.546	388.815	744
4	752.9	493.15	460.075	786
5	779.1	457.565	480.164	756
6	707.3	511.19	386.632	832
7	795	500.73	449.857	846
8	742.2	560.062	420.065	882
9	653.2	564.034	363.397	854
10	478.5	499.762	291.653	687
11	317.4	666.864	159.549	825
12	239.4	812.83	91.592	961
				9334

D1 Rate

First Block	$0.08035
Second Block	$0.09599
PSCR	-$0.000870
Service Charge	$7.50
Distribution Rate	$0.05529
Nuclear	0.000728
EO	$0.003396
LIEAF	$0.93
Total Fix	$8.43
Total Dist Surcha	$0.00412

Outflow Credit ($0.035)

Annual Summary	Total Bill	Bank Value Remaining
No gen	$1,447	N/A
Cat 1 NM	$455	$0
In/Out - LMP Outflow	$864	$0

D1 - no net meter

Month	Days	Total Use	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Total Bill
1	31	518	518	$41.59	0	0	-0.45	$41.14	$8.43	$28.62	$2.13	$39.18	$80.32
2	28	644	476	$38.25	168	16.16	-0.56	$53.85	$8.43	$35.63	$2.66	$46.72	$100.57
3	31	744	527	$42.34	217	20.8	-0.65	$62.49	$8.43	$41.12	$3.07	$52.62	$115.11
4	30	786	510	$40.98	276	26.49	-0.68	$66.79	$8.43	$43.46	$3.24	$55.13	$121.92
5	31	756	527	$42.34	229	22.03	-0.66	$63.71	$8.43	$41.83	$3.12	$53.38	$117.09
6	30	832	510	$40.98	322	30.89	-0.72	$71.15	$8.43	$45.99	$3.43	$57.85	$129.00
7	31	846	527	$42.34	319	30.61	-0.74	$72.21	$8.43	$46.77	$3.49	$58.69	$130.90
8	31	882	527	$42.34	355	34.1	-0.77	$75.67	$8.43	$48.78	$3.64	$60.85	$136.52
9	30	854	510	$40.98	344	33.01	-0.74	$73.25	$8.43	$47.21	$3.52	$59.16	$132.41
10	31	687	527	$42.34	160	15.32	-0.6	$57.06	$8.43	$37.96	$2.83	$49.22	$106.28
11	30	825	510	$40.98	315	30.21	-0.72	$70.47	$8.43	$45.60	$3.40	$57.43	$127.90
12	31	961	527	$42.34	434	41.63	-0.84	$83.13	$8.43	$53.12	$3.96	$65.51	$148.64
ANNUAL								$790.92				$655.74	$1,446.66

D1 - Category 1 Net Metering

Month	Days	Net Inflow	First Block kWh	First Block	Excess Gen Cred	Second Block kWh	Second Block Bill	Excess Gen Cred	PSCR Bill	Excess Gen Credit	PS Total	Fixed Charges	Distribution Bill	Excess Gen Cred	Dist Surch Bill	Dist subtotal	Total Bill	Bank Start	Bank Change	Bank End		
1	31	315	315	$25.33		0	0		-0.27		$25.06	$8.43	$17.43		$1.30	$27.16	$52.22	0	0	0		
2	28	150	150	$12.07		0	0		-0.13		$11.94	$8.43	$8.31		$0.62	$17.36	$29.30	0	0	0		
3	31	96	96	$7.69		0	0		-0.08		$7.61	$8.43	$5.29		$0.39	$14.11	$21.72	0	0	0		
4	30	33	33	$2.66		0	0		-0.03		$2.63	$8.43	$1.83		$0.14	$10.40	$13.03	0	0	0		
5	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	0	23	23		
6	30	125	125	$10.01	-$1.82	0	0		-0.11	$0.02	$8.10	$8.43	$6.89	-$1.25	$0.51	$14.58	$22.68	23	-23	0		
7	31	51	51	$4.09		0	0		-0.04		$4.05	$8.43	$2.81		$0.21	$11.45	$15.50	0	0	0		
8	31	140	140	$11.25		0	0		-0.12		$11.13	$8.43	$7.74		$0.58	$16.75	$27.88	0	0	0		
9	30	201	201	$16.12		0	0		-0.17		$15.95	$8.43	$11.09		$0.83	$20.35	$36.30	0	0	0		
10	31	208	208	$16.72		0	0		-0.18		$16.54	$8.43	$11.51		$0.86	$20.80	$37.34	0	0	0		
11	30	507	507	$40.76		0	0		-0.44		$40.32	$8.43	$28.05		$2.09	$38.57	$78.89	0	0	0		
12	31	721	527	$42.34		194	18.64		-0.63		$60.35	$8.43	$39.88		$2.97	$51.28	$111.63	0	0	0		
ANNUAL											$203.68					$251.24	$454.92			0	$0.13	$0.00

D1 - Inflow/outflow method at LMP Outflow Credit

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Outflow kWh	LMP Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	417	417	$33.49	0	0	-0.36	$33.13	$8.43	$23.05	$1.72	$33.20	102	-$3.55	$62.78	no excess	0	0	0
2	28	447	447	$35.95	0	0	-0.39	$35.56	$8.43	$24.74	$1.84	$35.01	297	-$10.40	$60.17	no excess	0	0	0
3	31	485	485	$38.93	0	0	-0.42	$38.51	$8.43	$26.79	$2.00	$37.22	389	-$13.61	$62.12	no excess	0	0	0
4	30	493	493	$39.62	0	0	-0.43	$39.19	$8.43	$27.27	$2.03	$37.73	460	-$16.10	$60.82	no excess	0	0	0
5	31	458	458	$36.77	0	0	-0.4	$36.37	$8.43	$25.30	$1.89	$35.62	480	-$16.81	$55.18	no excess	0	0	0
6	30	511	510	$40.98	1	0.11	-0.44	$40.65	$8.43	$28.26	$2.11	$38.80	387	-$13.53	$65.92	no excess	0	0	0
7	31	501	501	$40.23	0	0	-0.44	$39.79	$8.43	$27.69	$2.07	$38.19	450	-$15.74	$62.24	no excess	0	0	0
8	31	560	527	$42.34	33	3.17	-0.49	$45.02	$8.43	$30.97	$2.31	$41.71	420	-$14.70	$72.03	no excess	0	0	0
9	30	564	510	$40.98	54	5.19	-0.49	$45.68	$8.43	$31.19	$2.33	$41.95	363	-$12.72	$74.91	no excess	0	0	0
10	31	500	500	$40.16	0	0	-0.43	$39.73	$8.43	$27.63	$2.06	$38.12	292	-$10.21	$67.64	no excess	0	0	0
11	30	667	510	$40.98	157	15.06	-0.58	$55.46	$8.43	$36.87	$2.75	$48.05	160	-$5.58	$97.93	no excess	0	0	0
12	31	813	527	$42.34	286	27.44	-0.71	$69.07	$8.43	$44.94	$3.35	$56.72	92	-$3.21	$122.58	no excess	0	0	0
ANNUAL								$518.16				$482.32			$864.32				

D1 - Inflow/outflow method, grid charge, and LMP outflow

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Grid Charge	Outflow kWh	Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	417	417	$33.49	0	0	-0.36	$33.13	$8.43	$23.05	$1.72	$33.20	$11.59	102	-$3.55	$74.37	no excess	0	0	0
2	28	447	447	$35.95	0	0	-0.39	$35.56	$8.43	$24.74	$1.84	$35.01	$11.59	297	-$10.40	$71.76	no excess	0	0	0
3	31	485	485	$38.93	0	0	-0.42	$38.51	$8.43	$26.79	$2.00	$37.22	$11.59	389	-$13.61	$73.71	no excess	0	0	0
4	30	493	493	$39.62	0	0	-0.43	$39.19	$8.43	$27.27	$2.03	$37.73	$11.59	460	-$16.10	$72.41	no excess	0	0	0
5	31	458	458	$36.77	0	0	-0.4	$36.37	$8.43	$25.30	$1.89	$35.62	$11.59	480	-$16.81	$66.77	no excess	0	0	0
6	30	511	510	$40.98	1	0.11	-0.44	$40.65	$8.43	$28.26	$2.11	$38.80	$11.59	387	-$13.53	$77.51	no excess	0	0	0
7	31	501	501	$40.23	0	0	-0.44	$39.79	$8.43	$27.69	$2.07	$38.19	$11.59	450	-$15.74	$73.83	no excess	0	0	0
8	31	560	527	$42.34	33	3.17	-0.49	$45.02	$8.43	$30.97	$2.31	$41.71	$11.59	420	-$14.70	$83.62	no excess	0	0	0
9	30	564	510	$40.98	54	5.19	-0.49	$45.68	$8.43	$31.19	$2.33	$41.95	$11.59	363	-$12.72	$86.50	no excess	0	0	0
10	31	500	500	$40.16	0	0	-0.43	$39.73	$8.43	$27.63	$2.06	$38.12	$11.59	292	-$10.21	$79.23	no excess	0	0	0
11	30	667	510	$40.98	157	15.06	-0.58	$55.46	$8.43	$36.87	$2.75	$48.05	$11.59	160	-$5.58	$109.52	no excess	0	0	0
12	31	813	527	$42.34	286	27.44	-0.71	$69.07	$8.43	$44.94	$3.35	$56.72	$11.59	92	-$3.21	$134.17	no excess	0	0	0
								$518.16				$482.32	$139.08		-$136.16	$1,003.40				

Customer 1 Inputs

Month	Gen	In	Out	In + Gen - Out
1	38.01	339.165	15.007	362
2	150.5	345.449	92.793	403
3	401.4	365.403	304.503	462
4	675.7	335.652	515.642	496
5	750.1	347.502	581.889	516
6	730.8	303.246	530.504	504
7	762.7	310.506	555.758	517
8	687.4	347.136	513.97	521
9	486.2	344.369	329.455	501
10	251.6	397.399	124.075	525
11	137.4	571.55	56.103	653
12	134.7	490.716	59.75	566
				6025

D1 Rate

First Block	$0.08035	Outflow Credit	($0.035)
Second Block	$0.09599		
PSCR	-$0.000870		
Service Charge	$7.50		
Distribution Rate	$0.05529		
Nuclear	0.000728		
EO	$0.003396		
LIEAF	$0.93		
Total Fix	$8.43		
Total Dist Surcha	$0.00412		

Annual Summary	Total Bill	Bank Value Remaining
No gen	$941	N/A
Cat 1 NM	$220	$0
In/Out - LMP Outflow	$598	$0

D1 - no net meter

Month	Days	Total Use	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Total Bill
1	31	362	362	$29.10	0	0	-0.32	$28.78	$8.43	$20.02	$1.49	$29.94	$58.72
2	28	403	403	$32.40	0	0	-0.35	$32.05	$8.43	$22.29	$1.66	$32.38	$64.43
3	31	462	462	$37.14	0	0	-0.4	$36.74	$8.43	$25.56	$1.91	$35.90	$72.64
4	30	496	496	$39.83	0	0	-0.43	$39.40	$8.43	$27.41	$2.04	$37.88	$77.28
5	31	516	516	$41.44	0	0	-0.45	$40.99	$8.43	$28.51	$2.13	$39.07	$80.06
6	30	504	504	$40.46	0	0	-0.44	$40.02	$8.43	$27.84	$2.08	$38.35	$78.37
7	31	517	517	$41.58	0	0	-0.45	$41.13	$8.43	$28.61	$2.13	$39.17	$80.30
8	31	521	521	$41.82	0	0	-0.45	$41.37	$8.43	$28.78	$2.15	$39.36	$80.73
9	30	501	501	$40.27	0	0	-0.44	$39.83	$8.43	$27.71	$2.07	$38.21	$78.04
10	31	525	525	$42.18	0	0	-0.46	$41.72	$8.43	$29.02	$2.16	$39.61	$81.33
11	30	653	510	$40.98	143	13.71	-0.57	$54.12	$8.43	$36.10	$2.69	$47.22	$101.34
12	31	566	527	$42.34	39	3.71	-0.49	$45.56	$8.43	$31.27	$2.33	$42.03	$87.59
ANNUAL								$481.71				$459.12	$940.83

D1 - Category 1 Net Metering

Month	Days	Net Inflow	First Block kWh	First Block	Excess Gen Cred	Second Block kWh	Second Block Bill	Excess Gen Cred	PSCR Bill	Excess Gen Credit	PS Total	Fixed Charges	Distribution Bill	Excess Gen Cred	Dist Surch Bill	Dist subtotal	Total Bill	Bank Start	Bank Change	Bank End		
1	31	324	324	$26.05		0	0		-0.28		$25.77	$8.43	$17.92		$1.34	$27.69	$53.46	0	0	0		
2	28	253	253	$20.30		0	0		-0.22		$20.08	$8.43	$13.97		$1.04	$23.44	$43.52	0	0	0		
3	31	61	61	$4.89		0	0		-0.05		$4.84	$8.43	$3.37		$0.25	$12.05	$16.89	0	0	0		
4	30	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	0	180	179.99		
5	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	180	234	414		
6	30	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	414	227	642		
7	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	642	245	887		
8	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	887	167	1054		
9	30	15	15	$1.20	-$1.20	0	0		-0.01	0.01	$0.00	$8.43	$0.82	-$0.82	$0.06	$8.49	$8.49	1054	-15	1039		
10	31	273	273	$21.96	-$21.96	0	0		-0.24	0.24	$0.00	$8.43	$15.11	-$15.11	$1.13	$9.56	$9.56	1039	-273	765		
11	30	515	510	$40.98	-$40.98	5	0.52		-0.45	0.45	$0.52	$8.43	$28.50	-$28.50	$2.13	$10.56	$11.08	765	-515	250		
12	31	431	431	$34.63	-$20.09	0	0		-0.37	$0.22	$14.39	$8.43	$23.83	-$13.82	$1.78	$20.22	$34.61	250	-250	0		
ANNUAL											$65.60					$154.16	$219.76			0	$0.13	$0.00

D1 - Inflow/outflow method at LMP Outflow Credit

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Outflow kWh	LMP Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	339	339	$27.25	0	0	-0.3	$26.95	$8.43	$18.75	$1.40	$28.58	15	-$0.53	$55.00	no excess	0	0	0
2	28	345	345	$27.76	0	0	-0.3	$27.46	$8.43	$19.10	$1.42	$28.95	93	-$3.25	$53.16	no excess	0	0	0
3	31	365	365	$29.36	0	0	-0.32	$29.04	$8.43	$20.20	$1.51	$30.14	305	-$10.66	$48.52	no excess	0	0	0
4	30	336	336	$26.97	0	0	-0.29	$26.68	$8.43	$18.56	$1.38	$28.37	516	-$18.05	$37.00	no excess	0	0	0
5	31	348	348	$27.92	0	0	-0.3	$27.62	$8.43	$19.21	$1.43	$29.07	582	-$20.37	$36.32	no excess	0	0	0
6	30	303	303	$24.37	0	0	-0.26	$24.11	$8.43	$16.77	$1.25	$26.45	531	-$18.57	$31.99	no excess	0	0	0
7	31	311	311	$24.95	0	0	-0.27	$24.68	$8.43	$17.17	$1.28	$26.88	556	-$19.45	$32.11	no excess	0	0	0
8	31	347	347	$27.89	0	0	-0.3	$27.59	$8.43	$19.19	$1.43	$29.05	514	-$17.99	$38.65	no excess	0	0	0
9	30	344	344	$27.67	0	0	-0.3	$27.37	$8.43	$19.04	$1.42	$28.89	329	-$11.53	$44.73	no excess	0	0	0
10	31	397	397	$31.93	0	0	-0.35	$31.58	$8.43	$21.97	$1.64	$32.04	124	-$4.34	$59.28	no excess	0	0	0
11	30	572	510	$40.98	62	5.91	-0.5	$46.39	$8.43	$31.60	$2.36	$42.39	56	-$1.96	$86.82	no excess	0	0	0
12	31	491	491	$39.43	0	0	-0.43	$39.00	$8.43	$27.13	$2.02	$37.58	60	-$2.09	$74.49	no excess	0	0	0
ANNUAL								$358.47				$368.39			$598.08				

D1 - Inflow/outflow method, grid charge, and LMP outflow

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Grid Charge	Outflow kWh	Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	339	339	$27.25	0	0	-0.3	$26.95	$8.43	$18.75	$1.40	$28.58	$12.20	15	-$0.53	$67.21	no excess	0	0	0
2	28	345	345	$27.76	0	0	-0.3	$27.46	$8.43	$19.10	$1.42	$28.95	$12.20	93	-$3.25	$65.36	no excess	0	0	0
3	31	365	365	$29.36	0	0	-0.32	$29.04	$8.43	$20.20	$1.51	$30.14	$12.20	305	-$10.66	$60.72	no excess	0	0	0
4	30	336	336	$26.97	0	0	-0.29	$26.68	$8.43	$18.56	$1.38	$28.37	$12.20	516	-$18.05	$49.20	no excess	0	0	0
5	31	348	348	$27.92	0	0	-0.3	$27.62	$8.43	$19.21	$1.43	$29.07	$12.20	582	-$20.37	$48.52	no excess	0	0	0
6	30	303	303	$24.37	0	0	-0.26	$24.11	$8.43	$16.77	$1.25	$26.45	$12.20	531	-$18.57	$44.19	no excess	0	0	0
7	31	311	311	$24.95	0	0	-0.27	$24.68	$8.43	$17.17	$1.28	$26.88	$12.20	556	-$19.45	$44.31	no excess	0	0	0
8	31	347	347	$27.89	0	0	-0.3	$27.59	$8.43	$19.19	$1.43	$29.05	$12.20	514	-$17.99	$50.85	no excess	0	0	0
9	30	344	344	$27.67	0	0	-0.3	$27.37	$8.43	$19.04	$1.42	$28.89	$12.20	329	-$11.53	$56.93	no excess	0	0	0
10	31	397	397	$31.93	0	0	-0.35	$31.58	$8.43	$21.97	$1.64	$32.04	$12.20	124	-$4.34	$71.48	no excess	0	0	0
11	30	572	510	$40.98	62	5.91	-0.5	$46.39	$8.43	$31.60	$2.36	$42.39	$12.20	56	-$1.96	$99.02	no excess	0	0	0
12	31	491	491	$39.43	0	0	-0.43	$39.00	$8.43	$27.13	$2.02	$37.58	$12.20	60	-$2.09	$86.69	no excess	0	0	0
								$358.47				$368.39	$146.41		-$128.78	$744.48				

Customer 1 Inputs

Month	Gen	In	Out	In + Gen - Out
1	79.41	1015.05	30.16	1064
2	103.66	1373.16	38.14	1439
3	916.79	1121.34	776.75	1261
4	1822.45	829.72	1395.71	1256
5	2045.13	513.38	1727.77	831
6	2058.83	737.04	1513.34	1283
7	2127.52	761.89	1600.13	1289
8	1595.28	641.38	1386.30	850
9	1590.01	840.37	1188.64	1242
10	1008.71	968.02	724.37	1252
11	529.43	1080.81	325.16	1285
12	476.29	1384.31	208.90	1652
				14705

D1 Rate

First Block	$0.08035
Second Block	$0.09599
PSCR	-$0.000870
Service Charge	$7.50
Distribution Rate	$0.05529
Nuclear	0.000728
EO	$0.003396
LIEAF	$0.93
Total Fix	$8.43
Total Dist Surcha	$0.00412

Outflow Credit	($0.035)

Annual Summary	Total Bill	Bank Value Remaining
No gen	$2,276	N/A
Cat 1 NM	$587	$311.78
In/Out - LMP Outflow	$1,363	0.00

D1 - no net meter

Month	Days	Total Use	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Total Bill
1	31	1064	527	$42.34	537	51.58	-0.93	$92.99	$8.43	$58.85	$4.39	$71.67	$164.66
2	28	1439	476	$38.25	963	92.41	-1.25	$129.41	$8.43	$79.54	$5.93	$93.90	$223.31
3	31	1261	527	$42.34	734	70.49	-1.1	$111.73	$8.43	$69.74	$5.20	$83.37	$195.10
4	30	1256	510	$40.98	746	71.65	-1.09	$111.54	$8.43	$69.47	$5.18	$83.08	$194.62
5	31	831	527	$42.34	304	29.16	-0.72	$70.78	$8.43	$45.93	$3.43	$57.79	$128.57
6	30	1283	510	$40.98	773	74.15	-1.12	$114.01	$8.43	$70.91	$5.29	$84.63	$198.64
7	31	1289	527	$42.34	762	73.17	-1.12	$114.39	$8.43	$71.28	$5.32	$85.03	$199.42
8	31	850	527	$42.34	323	31.04	-0.74	$72.64	$8.43	$47.02	$3.51	$58.96	$131.60
9	30	1242	510	$40.98	732	70.24	-1.08	$110.14	$8.43	$68.66	$5.12	$82.21	$192.35
10	31	1252	527	$42.34	725	69.63	-1.09	$110.88	$8.43	$69.24	$5.16	$82.83	$193.71
11	30	1285	510	$40.98	775	74.4	-1.12	$114.26	$8.43	$71.05	$5.30	$84.78	$199.04
12	31	1652	527	$42.34	1125	107.96	-1.44	$148.86	$8.43	$91.32	$6.81	$106.56	$255.42
ANNUAL								$1,301.63				$974.81	$2,276.44

D1 - Category 1 Net Metering

Month	Days	Net Inflow	First Block kWh	First Block	Excess Gen Cred	Second Block kWh	Second Block Bill	Excess Gen Cred	PSCR Bill	Excess Gen Credit	PS Total	Fixed Charges	Distribution Bill	Excess Gen Cred	Dist Surch Bill	Dist subtotal	Total Bill	Bank Start	Bank Change	Bank End		
1	31	985	527	$42.34		458	43.95		-0.86		$85.43	$8.43	$54.45		$4.06	$66.94	$152.37	0	0	0		
2	28	1335	476	$38.25		859	82.46		-1.16		$119.55	$8.43	$73.81		$5.51	$87.75	$207.30	0	0	0		
3	31	345	345	$27.69		0	0		-0.3		$27.39	$8.43	$19.05		$1.42	$28.90	$56.29	0	0	0		
4	30	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	0	566	566		
5	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	566	1214	1780		
6	30	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	1780	776	2557		
7	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	2557	838	3395		
8	31	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	3395	745	4140		
9	30	0	0	$0.00		0	0		0		$0.00	$8.43	$0.00		$0.00	$8.43	$8.43	4140	348	4488		
10	31	244	244	$19.58	-$19.58	0	0		-0.21	0.21	$0.00	$8.43	$13.47	-$13.47	$1.00	$9.43	$9.43	4488	-244	4244		
11	30	756	510	$40.98	-$40.98	246	23.58		-0.66	0.66	$23.58	$8.43	$41.78	-$41.78	$3.12	$11.55	$35.13	4244	-756	3489		
12	31	1175	527	$42.34	-$42.34	648	62.24		-1.02	1.02	$62.24	$8.43	$64.99	-$64.99	$4.85	$13.28	$75.52	3489	-1175	2313		
ANNUAL											$318.19					$268.43	$586.62			2313	$0.13	$311.78

D1 - Inflow/outflow method at LMP Outflow Credit

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Outflow kWh	LMP Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	1015	527	$42.34	488	46.85	-0.88	$88.31	$8.43	$56.12	$4.19	$68.74	30	-$1.06	$155.99	no excess	0.00	0	0.00
2	28	1373	476	$38.25	897	86.12	-1.19	$123.18	$8.43	$75.92	$5.66	$90.01	38	-$1.33	$211.86	no excess	0.00	0	0.00
3	31	1121	527	$42.34	594	57.05	-0.98	$98.41	$8.43	$62.00	$4.62	$75.05	777	-$27.19	$146.27	no excess	0.00	0	0.00
4	30	830	510	$40.98	320	30.69	-0.72	$70.95	$8.43	$45.88	$3.42	$57.73	1396	-$48.85	$79.83	no excess	0.00	$0.00	0.00
5	31	513	513	$41.25	0	0	-0.45	$40.80	$8.43	$28.38	$2.12	$38.93	1728	-$60.47	$19.26	no excess	0.00	$0.00	0.00
6	30	737	510	$40.98	227	21.79	-0.64	$62.13	$8.43	$40.75	$3.04	$52.22	1513	-$52.97	$61.38	no excess	0.00	$0.00	0.00
7	31	762	527	$42.34	235	22.55	-0.66	$64.23	$8.43	$42.12	$3.14	$53.69	1600	-$56.00	$61.92	no excess	0.00	$0.00	0.00
8	31	641	527	$42.34	114	10.98	-0.56	$52.76	$8.43	$35.46	$2.65	$46.54	1386	-$48.52	$50.78	no excess	0.00	$0.00	0.00
9	30	840	510	$40.98	330	31.71	-0.73	$71.96	$8.43	$46.46	$3.47	$58.36	1189	-$41.60	$88.72	no excess	0.00	$0.00	0.00
10	31	968	527	$42.34	441	42.33	-0.84	$83.83	$8.43	$53.52	$3.99	$65.94	724	-$25.35	$124.42	no excess	0.00	$0.00	0.00
11	30	1081	510	$40.98	571	54.79	-0.94	$94.83	$8.43	$59.76	$4.46	$72.65	325	-$11.38	$156.10	no excess	0.00	$0.00	0.00
12	31	1384	527	$42.34	857	82.29	-1.2	$123.43	$8.43	$76.54	$5.71	$90.68	209	-$7.31	$206.80	no excess	0.00	0.00	0.00
ANNUAL								$974.82				$770.54			$1,363.32				
															653.82				

D1 - Inflow/outflow method, grid charge, and LMP outflow

Month	Days	Total Inflow	First Block kWh	First Block	Second Block kWh	Second Block Bill	PSCR Bill	PS Total	Fixed Charges	Distribution Bill	Dist Surch Bill	Dist subtotal	Grid Charge	Outflow kWh	Outflow Cred	Total Bill		Bank Start	ank Chang	Bank End
1	31	1015	527	$42.34	488	46.85	-0.88	$88.31	$8.43	$56.12	$4.19	$68.74	$20.50	30	-$1.06	$176.49	no excess	0	0	0
2	28	1373	476	$38.25	897	86.12	-1.19	$123.18	$8.43	$75.92	$5.66	$90.01	$20.50	38	-$1.33	$232.35	no excess	0	0	0
3	31	1121	527	$42.34	594	57.05	-0.98	$98.41	$8.43	$62.00	$4.62	$75.05	$20.50	777	-$27.19	$166.77	no excess	0	0	0
4	30	830	510	$40.98	320	30.69	-0.72	$70.95	$8.43	$45.88	$3.42	$57.73	$20.50	1396	-$48.85	$100.33	no excess	0	0	0
5	31	513	513	$41.25	0	0	-0.45	$40.80	$8.43	$28.38	$2.12	$38.93	$20.50	1728	-$60.47	$39.75	no excess	0	0	0
6	30	737	510	$40.98	227	21.79	-0.64	$62.13	$8.43	$40.75	$3.04	$52.22	$20.50	1513	-$52.97	$81.88	no excess	0	0	0
7	31	762	527	$42.34	235	22.55	-0.66	$64.23	$8.43	$42.12	$3.14	$53.69	$20.50	1600	-$56.00	$82.41	no excess	0	0	0
8	31	641	527	$42.34	114	10.98	-0.56	$52.76	$8.43	$35.46	$2.65	$46.54	$20.50	1386	-$48.52	$71.28	no excess	0	0	0
9	30	840	510	$40.98	330	31.71	-0.73	$71.96	$8.43	$46.46	$3.47	$58.36	$20.50	1189	-$41.60	$109.21	no excess	0	0	0
10	31	968	527	$42.34	441	42.33	-0.84	$83.83	$8.43	$53.52	$3.99	$65.94	$20.50	724	-$25.35	$144.91	no excess	0	0	0
11	30	1081	510	$40.98	571	54.79	-0.94	$94.83	$8.43	$59.76	$4.46	$72.65	$20.50	325	-$11.38	$176.60	no excess	0	0	0
12	31	1384	527	$42.34	857	82.29	-1.2	$123.43	$8.43	$76.54	$5.71	$90.68	$20.50	209	-$7.31	$227.30	no excess	0	0	0
								$974.82				$770.54	$245.96		-$382.04	$1,609.28				

DTEE Ranking using Annual Bill

	Cust 1	Cust 2	Cust 3	Cust 4	Cust 5	AVG	
Yearly on-site usage (kWh)	7,803	5,316	9,334	6,025	14,705	8,637	
Generator Size in kW	4.2	1.0	4.8	5.0	8.4	4.7	
							Incr. over NM
No DG	$1,212	$841	$1,447	$941	$2,276	$1,343	
In/Out - LMP Outflow @ 3.5 cents	$862	$717	$864	$598	$1,363	$881	80%
In/Out, grid charge, and LMP 3.5	$985	$746	$1,003	$744	$1,609	$1,018	108%
Cat 1 - Current Net Metering Program	$500	$681	$455	$220	$587	$488	0%

MPSC Case No.: U-20162
Requestor: ELPC
Question No.: ELPCDE-1.24a
Respondent: C. Serna / R. Mueller
Page: 1 of 1

Question: Please refer to Testimony of Witness C. Serna at 51, Lines 5-13, where witness Serna states:

"[D]istributed generation customers receive a range of additional grid services from the electric system that are unique to their choice to utility distributed generation. They leverage the electric system above and beyond traditional customers, make more intensive demands of the infrastructure, and generally use the electric system itself as a transactional service provider and balancing resource to meet their energy needs when their generation (primarily solar panels) is not operating at full output or when there are additional electrical demands that solar can't meet (eg., start-up of large appliances)."

a. Provide all documentation produced or reviewed by the Company which supports the assertion that DG customers "make more intensive demands of the infrastructure."

Answer: The Company has not developed or reviewed documentation of the impacts of distributed generation customers on the Company's system. However, the topic of how distributed generation customers leverage the electric system is an important topic of research by the Electric Power Research Institute (EPRI) – an independent, non-profit research organization. The report titled "The Integrated Grid" provides information on the way distributed generation customers interact with the grid and the type of services provided by the grid to support these customers. Please see attachment "ELPCDE-1.24a The Integrated Grid."

MPSC Case No.: U-20162
Requestor: ELPC
Question No.: ELPCDE-1.24b
Respondent: C. Serna/Legal
Page: 1 of 1

Question: Please refer to Testimony of Witness C. Serna at 51, Lines 5-13, where witness Serna states:

"[D]istributed generation customers receive a range of additional grid services from the electric system that are unique to their choice to utility distributed generation. They leverage the electric system above and beyond traditional customers, make more intensive demands of the infrastructure, and generally use the electric system itself as a transactional service provider and balancing resource to meet their energy needs when their generation (primarily solar panels) is not operating at full output or when there are additional electrical demands that solar can't meet (eg., start-up of large appliances)."

b. Please confirm or deny. The Company takes title to the outflow from DG customers when the power passes the DG customer's meter and enters the utility-owned distribution system. [If the Company denies this assertion, please explain the reason for the denial.]

Answer: DTE Electric objects to the request for the reason that the request is vague and incapable of answer in its current form, as the meaning of the term "takes title" is unclear.

Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

The Company confirms that outflow power from distributed generation customers 'enters the utility-owned distribution system.

MPSC Case No.: U-20162
Requestor: ELPC
Question No.: ELPCDE-1.24c
Respondent: C. Serna / R. Mueller
Page: 1 of 1

Question: Please refer to Testimony of Witness C. Serna at 51, Lines 5-13, where witness Serna states:

"[D]istributed generation customers receive a range of additional grid services from the electric system that are unique to their choice to utility distributed generation. They leverage the electric system above and beyond traditional customers, make more intensive demands of the infrastructure, and generally use the electric system itself as a transactional service provider and balancing resource to meet their energy needs when their generation (primarily solar panels) is not operating at full output or when there are additional electrical demands that solar can't meet (eg., start-up of large appliances)."

c. Please confirm or deny. The Company delivers the outflow from a DG customer to other customers on the Company's system. [If the Company denies this assertion, please explain the reason for the denial.]

Answer: The Company confirms that "the outflow power that enters the utility-owned distribution system" becomes part of the overall power flowing in the system. Power in the system can be, in general, ultimately delivered to individual customers at wholesale for resale as well as for end use consumption.

MPSC Case No.:	U-20162
Requestor:	ELPC
Question No.:	ELPCDE-1.24d
Respondent:	C. Serna
Page:	1 of 1

Question: Please refer to Testimony of Witness C. Serna at 51, Lines 5-13, where witness Serna states:

"[D]istributed generation customers receive a range of additional grid services from the electric system that are unique to their choice to utility distributed generation. They leverage the electric system above and beyond traditional customers, make more intensive demands of the infrastructure, and generally use the electric system itself as a transactional service provider and balancing resource to meet their energy needs when their generation (primarily solar panels) is not operating at full output or when there are additional electrical demands that solar can't meet (eg., start-up of large appliances)."

d. Please confirm or deny. The customer who ultimately consumes the excess DG generation ("outflow") exported to the Company's system will pay the Company for the delivery of that power to their premises. [If the Company denies this assertion, please explain the reason for the denial.]

Answer: The Company confirms that non-DG customers pay a delivery charge for the power delivered to their premises.

MPSC Case No.: U-20162
Requestor: ELPC
Question No.: ELPCDE-1.24e
Respondent: T. W. Lacey
Page: 1 of 1

Question: Please refer to Testimony of Witness C. Serna at 51, Lines 5-13, where witness Serna states:

"[D]istributed generation customers receive a range of additional grid services from the electric system that are unique to their choice to utility distributed generation. They leverage the electric system above and beyond traditional customers, make more intensive demands of the infrastructure, and generally use the electric system itself as a transactional service provider and balancing resource to meet their energy needs when their generation (primarily solar panels) is not operating at full output or when there are additional electrical demands that solar can't meet (eg., start-up of large appliances)."

e. Provide all analyses produced by (or for) the Company that calculate the cost to serve net metering customers both independently and compared to traditional customers, including all cost of service studies specific to net metering customers.

Answer: Please see the Company's response to ELPCDE-1.23.

MPSC Case No.: U-20162
Requestor: ELPC
Question No.: ELPCDE-1.24f
Respondent: C. Serna / R. Mueller
Page: 1 of 1

Question: Please refer to Testimony of Witness C. Serna at 51, Lines 5-13, where witness Serna states:

"[D]istributed generation customers receive a range of additional grid services from the electric system that are unique to their choice to utility distributed generation. They leverage the electric system above and beyond traditional customers, make more intensive demands of the infrastructure, and generally use the electric system itself as a transactional service provider and balancing resource to meet their energy needs when their generation (primarily solar panels) is not operating at full output or when there are additional electrical demands that solar can't meet (eg., start-up of large appliances)."

f. Please provide all analyses produced by (or for) the Company that demonstrates that outflow energy from current net metering customers is ever exported beyond the distribution substation level of the distribution system.

Answer: The Company has not performed such analyses.

MPSC Case No.:	U-20162
Requestor:	ELPC
Question No.:	ELPCDE-1.24g
Respondent:	C. Serna / R. Mueller
Page:	1 of 1

Question: Please refer to Testimony of Witness C. Serna at 51, Lines 5-13, where witness Serna states:

"[D]istributed generation customers receive a range of additional grid services from the electric system that are unique to their choice to utility distributed generation. They leverage the electric system above and beyond traditional customers, make more intensive demands of the infrastructure, and generally use the electric system itself as a transactional service provider and balancing resource to meet their energy needs when their generation (primarily solar panels) is not operating at full output or when there are additional electrical demands that solar can't meet (eg., start-up of large appliances)."

g. Please explain if the Company has studies or calculated the benefits provided by distributed generation customers to the distribution system. If it has, please provide that study or calculations.

Answer: The Company has not performed such study or calculation.

MPSC Case No.: U-20162
Requestor: MECNRDCSCDE
Question No.: MECNRDCSCDE-1.17d
Respondent: P. W. Dennis
Page: 1 of 1

Question: Please reference Dennis Direct at 20:15-21:13 and Exhibit A-16, Schedule F9.

d. Please confirm that you designed the proposed SAC to recover the amount of distribution revenue that DG customers would have paid through kWh charges if they had not reduced purchases of grid-supplied electricity by self-generating.

Answer: For individual customers this may not be true, however, on an overall basis, I confirm.

MPSC Case No.:	U-20162
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-3.4a
Respondent:	P. W. Dennis
Page:	1 of 1

Question: Please reference DTE Response to MEC DR 1.7(a), 1.10(a) and 1.17(f).

a) Please confirm that on an overall sub-class basis (i.e., all customers subject to the System Access Contribution), the System Access Contribution and inflow charges will recover the same level of distribution revenue from those customers than if those customers supplied none of their electricity consumption through behind the meter generation.

Answer: As stated in the responses to MECNRDCSCDE1.17(d) and (f), on an overall basis (using 2017 data as a proxy for future loads), the System Access Contribution charge when combined with the inflow charge, is designed to recover the distribution revenue if no electricity was consumed with behind the meter generation, however, impacts on customers would vary.

Attachments: *n/a*

MPSC Case No.:	U-20162
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-3.9
Respondent:	P. W. Dennis
Page:	1 of 1

Question: Please reference Serna Direct at CS-59:24-25. Please provide any connection and/or correlation between an individual distributed generation customer's nameplate system capacity and his or her contribution to the peak loads, energy, and customer counts used in the unbundled cost of service study you conducted for this case.

Answer: The Company did not undertake a review or study any connection and/or correlation between an individual distributed generation customer's nameplate system capacity and his or her contribution to the peak loads, energy, and customer counts.

Attachments: n/a

MPSC Case No.: U-20162
Requestor: MECNRDCSCDE
Question No.: MECNRDCSCDE-1.10a
Respondent: C. Serna/K.O. Farrell/T. W. Lacey
Page: 1 of 1

Question: Please reference Serna Direct at 61:1-18.

a. Please confirm that DG customers have lower average contribution to class demands during the class NCP hours used to allocate distribution system capacity costs than non-DG customers in the same class.

Answer: Confirmed. However, class NCP hours is only one of the components of allocating distribution costs. A list of all distribution allocators is included on Workpaper WPA16F1 Support Schedule 2.

MPSC Case No.: U-20162
Requestor: MECNRDCSCDE
Question No.: MECNRDCSCDE-1.2a Revised
Respondent: C. Serna / R. J. Mueller
Page: 1 of 1

Question: Please reference Serna Direct at 53:9-20.

a. Please identify each instance when a residential or secondary commercial customer with distributed generation ("DG") experienced an inverter tripping offline that caused DTE Electric Company ("DTE") protective equipment to trip the circuit offline.

Answer: The Company does not have a record that this has occurred due to a residential or secondary commercial customer with distributed generation ("DG") on the Company's system to date.

MPSC Case No.:	U-20162
Requestor:	MECNRDCSCDE
Question No.:	MECNRDCSCDE-1.2b Revised
Respondent:	C. Serna / R. J. Mueller
Page:	1 of 1

Question: Please reference Serna Direct at 53:9-20.

b. Please identify each instance when a residential or secondary commercial customer with DG experienced rapid cloud cover change that caused DTE protective equipment to trip the circuit offline.

Answer: The Company does not have a record that this has occurred due to a residential or secondary commercial customer with DG on the Company's system to date.

MPSC Case No.: U-20162
Requestor: MECNRDCSCDE
Question No.: MECNRDCSCDE-1.2c Revised
Respondent: C. Serna / R. J. Mueller
Page: 1 of 1

Question: Please reference Serna Direct at 53:9-20.

c. Please identify each instance when a residential or secondary commercial customer with DG caused reverse power flow that required equipment to be reconfigured or replaced, the cost of that reconfiguration or replacement, and whether the DG customer was charged for such reconfiguration or replacement through the applicable interconnection process.

Answer: The Company does not have any specific records of upgrades due to DG-driven reverse power flow for residential or secondary commercial customers with DG. There have been instances of regulator, relay and recloser settings changes, service line upgrades and transformer replacement to support interconnection. However, the Company notes that current cost of service regulations do not support the individual assignment of the costs for secondary circuit level upgrades.

MPSC Case No.: U-20162
Requestor: MECNRDCSCDE
Question No.: MECNRDCSCDE-1.11
Respondent: T. W. Lacey
Page: 1 of 1

Question: Please reference Serna Direct at 61:19-62:2. Have you quantified the cost of providing inrush current as an unbundled service? If so, please provide the cost and produce all data, calculations, and workpapers used to quantify the cost.

Answer: I have not been asked to perform, nor am I aware of any studies quantifying the cost of providing inrush current as an unbundled service.

MPSC Case No.:	U-20162
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-3.6a
Respondent:	C. Serna/K. O. Farrell
Page:	1 of 1

Question: Please reference Serna Direct at CS-54:20-22.

a) State whether you contend that installing distributed generation reduces a customer's contribution to 4CP, 12CP, and NCP class loads by a smaller amount than the distributed generation reduces kWh inflows? If so, identify the percentage reduction in distributed generation customer's contribution 4CP, 12CP, and NCP class loads and the percentage reduction in kWh inflows.

Answer: The Company does not "contend that installing distributed generation reduces a customer's contribution to 4CP, 12CP, and NCP class loads by a smaller amount than the distributed generation reduces kWh inflows". The referenced text describes the current cost recovery paradigm in Michigan and makes no specific claim of 4CP, 12CP, and NCP behaviors.

Attachments: *n/a*

MPSC Case No.:	U-20162
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-3.16b
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: Please reference DTE Response to MEC 1.24(c) and (g).

b) How does DTE determine the portion of dues paid to EEI "below the line in account, 426.4, Political and Civil Activities" that are not charged to ratepayers?

Answer: Edison Electric Institute (EEI) identifies the portion of dues that relate to influencing legislation on the invoice.

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	Case No. U-20162 ALJ Sally L. Wallace

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony of Karl R. Rábago on behalf of MEC-NRDC-SC, EIBC, and IEI and Exhibits MEC-13 through MEC-31 with MEC-21 being Reserved** were served on the following:

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The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC-NRDC-SC

Date: November 7, 2018

By: Kimberly Flynn

Digitally signed by Kimberly Flynn
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